ERCOT Nodal Protocols

January 27, 2023

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ERCOT Nodal Protocols

Section 1: Overview

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1 OVERVIEW

1.1 Summary of the ERCOT Protocols Document

(1) The Electric Reliability Council of Texas (ERCOT) Protocols, created through the collaborative efforts of representatives of all segments of Market Participants, means the document adopted by ERCOT, including any attachments or exhibits referenced in these Protocols, as amended from time to time, that contains the scheduling, operating, planning, reliability, and Settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. To determine responsibilities at a given time, the version of the ERCOT Protocols in effect at the time of the performance or non-performance of an action governs with respect to that action. These Protocols are intended to implement ERCOT's functions as the Independent Organization for the ERCOT Region as certified by the Public Utility Commission of Texas (PUCT) and as the Program Administrator appointed by the PUCT that is responsible for carrying out the administrative responsibilities related to the Renewable Energy Credit (REC) Program as set forth in subsection (g) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. Market Participants, the Independent Market Monitor (IMM), and ERCOT shall abide by these Protocols.

(2) The ERCOT Board, Technical Advisory Committee (TAC), and other ERCOT subcommittees authorized by the ERCOT Board or TAC or ERCOT may develop polices, guidelines, procedures, forms, and applications for the implementation of and operation under, these Protocols and to comply with applicable rules, laws, and orders of a Governmental Authority. A policy, guideline, procedure, form, or application described above is an "Other Binding Document." Other Binding Documents do not include ERCOT's internal administrative procedures, documents and processes necessary to fulfill its role as the Independent Organization or as a registered Entity with the North American Electric Reliability Corporation (NERC).

(3) ERCOT shall post the Other Binding Documents List and all Other Binding Documents to a part of the ERCOT website reserved for posting Other Binding Documents. A TAC designated subcommittee shall review the Other Binding Documents List at least every four years, and modifications to the Other Binding Documents List shall be reviewed and considered by the TAC designated subcommittee and by TAC at its next scheduled meeting.

(4) Any revision of an Other Binding Document must follow the revision process set forth in that Other Binding Document. If an Other Binding Document does not specify a revision process, the Other Binding Document shall be subject to the procedures in Section 21, Revision Request Process, and shall be treated as if it were a Protocol for purposes of the revision process.

(5) To the extent that Other Binding Documents are not in conflict with these Protocols or with an Agreement to which it is a party, each Market Participant, the IMM, and ERCOT shall abide by the Other Binding Documents. Taken together, these Protocols and the

Other Binding Documents constitute all of the “scheduling, operating, planning, reliability, and Settlement policies, rules, guidelines, and procedures established by the independent System Operator in ERCOT,” as that phrase is used in subsection (j) of the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2007) (PURA), Essential Organizations, that bind Market Participants.

(6) Except as provided below, if the provisions in any attachment to these Protocols or in any of the Other Binding Documents conflict with the provisions of Section 1, Overview, through Section 21, and Section 24, Retail Point to Point Communications, through Section 27, Securitization Uplift Charges, then the provisions of Section 1 through Section 21, and Section 24 through Section 27 prevail to the extent of the inconsistency. If any provision of any Agreement conflicts with any provision of the Protocols, the Agreement prevails to the extent of the conflict. Any Agreement provision that deviates from the standard form for that Agreement in Section 22, Attachments, must expressly state that the Agreement provision deviates from the standard form in Section 22. Agreement provisions that deviate from the Protocols are effective only upon approval by the ERCOT Board on a showing of good cause.

(7) These Protocols are not intended to govern the direct relationships between or among Market Participants except as expressly provided in these Protocols. ERCOT is not responsible for any relationship between or among Market Participants to which ERCOT is not a party.

1.2 Functions of ERCOT

(1) ERCOT is the Independent Organization certified by the Public Utility Commission of Texas (PUCT) for the ERCOT Region. The major functions of ERCOT, as the Independent Organization, are to:

(a) Ensure access to the ERCOT Transmission Grid and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms;

(b) Ensure the reliability and adequacy of the ERCOT Transmission Grid;

(c) Ensure that information relating to a Customer’s choice of Retail Electric Provider (REP) in Texas is conveyed in a timely manner to the persons who need that information; and

(d) Ensure that electricity production and delivery are accurately accounted for among the Generation Resources and Settlement Only Generators (SOGs) and wholesale buyers and sellers, and Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs), in the ERCOT Region.

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

(d) Ensure that electricity production and delivery are accurately accounted for among wholesale buyers and sellers, and Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs), in the ERCOT Region.

(2) ERCOT is the Control Area Operator (CAO) for the ERCOT interconnection and performs all Control Area functions as defined in the Operating Guides and the North American Electric Reliability Corporation (NERC) policies.

(3) ERCOT procures Ancillary Services to ensure the reliability of the ERCOT System.

(4) ERCOT is the central counterparty for all transactions settled by ERCOT pursuant to these Protocols and is deemed to be the sole buyer to each seller, and the sole seller to each buyer, of all energy, Ancillary Services, Reliability Unit Commitments (RUCs), Emergency Response Service (ERS), and other products or services for which ERCOT may pay or charge a Market Participant, except for those products or services procured through bilateral transactions between Market Participants and those products or services that are self-arranged by Market Participants.

(5) ERCOT is the PUCT-appointed Program Administrator of the Renewable Energy Credits (RECs) Program.

(6) These Protocols are intended to implement the above-described functions. In the exercise of its sole discretion under these Protocols, ERCOT shall act in a reasonable, nondiscriminatory manner.

(7) Nothing in these Protocols may be construed as causing TSPs, DSPs, or Resources to transfer any control of their Facilities to ERCOT.

[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(7) Nothing in these Protocols may be construed as causing TSPs, DSPs, Direct Current Tie Operators (DCTOs), or Resources to transfer any control of their Facilities to ERCOT.

(8) ERCOT may not profit financially from its activities as the Independent Organization in the ERCOT Region. ERCOT may not use its discretion in the procurement of Ancillary Service capacity or deployment of energy to influence, set or control prices.

(9) Notwithstanding any other provision in these Protocols, ERCOT shall take any action, and shall direct any Market Participant to take any action, that ERCOT deems necessary to ensure that any Entity in the ERCOT Region that is not a "public utility" as defined in the Federal Power Act (FPA), including ERCOT, does not become such a public utility. ERCOT's authority includes, but is not limited to, the authority to order the disconnection of any Transmission Facilities connecting the ERCOT Region to another Control Area and the authority to deny or curtail Electronic Tags (e-Tags) over any Direct Current Tie (DC Tie). A Market Participant shall comply with any ERCOT directive provided under this section. ERCOT shall provide notice of any action pursuant to this provision by posting an operations message to the ERCOT website and issuing a Market Notice.

1.3 Confidentiality

(1) This Section 1.3 applies to Protected Information or ERCOT Critical Energy Infrastructure Information (ECEII) disclosed by a Market Participant to ERCOT or the Independent Market Monitor (IMM), by the IMM to ERCOT or a Market Participant, or by ERCOT to a Market Participant or the IMM. Section 1.3 also applies to specific categories of ECEII created by ERCOT, the IMM, or any Market Participant.

(2) As used in this Section 1.3:

(a) "Receiving Party" means ERCOT, the IMM or any Market Participant in its capacity as the recipient of Protected Information or ECEII from one of the others.

(b) "Disclosing Party" means ERCOT, the IMM or any Market Participant in its capacity as the provider of Protected Information or ECEII to one of the others.

(c) "Creating Party" means ERCOT, the IMM or any Market Participant in its capacity as the creator of any ECEII specifically listed in Section 1.3.2.1, Items Considered ERCOT Critical Energy Infrastructure Information.

(d) To disclose means to directly or indirectly disclose, reveal, distribute, report, publish, or transfer Protected Information or ECEII to any party other than to the Disclosing Party.

1.3.1 Restrictions on Protected Information

(1) A Receiving Party may not disclose Protected Information received from a Disclosing Party to any other Entity except as specifically permitted in this Section and in these Protocols. A Receiving Party may not knowingly use Protected Information for any illegal purpose.

1.3.1.1 Items Considered Protected Information

(1) Subject to the exclusions set out in Section 1.3.1.2, Items Not Considered Protected Information, and in Section 3.2.5, Publication of Resource and Load Information, "Protected Information" is information containing or revealing any of the following:

(a) Base Points, as calculated by ERCOT. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(b) Bids, offers, or pricing information identifiable to a specific Qualified Scheduling Entity (QSE) or Resource. The Protected Information status of part of this information shall expire 60 days after the applicable Operating Day, as follows:

(i) Ancillary Service Offers by Operating Hour for each Resource for all Ancillary Services submitted for the Day-Ahead Market (DAM) or any Supplemental Ancillary Services Market (SASM);

(ii) The quantity of Ancillary Service offered by Operating Hour for each Resource for all Ancillary Service submitted for the DAM or any SASM; and

(iii) Energy Offer Curve prices and quantities for each Settlement Interval by Resource. The Protected Information status of this information shall expire within seven days after the applicable Operating Day if required to be posted as part of paragraph (5) of Section 3.2.5 and within two days after the applicable Operating Day if required to be posted as part of paragraph (7) of Section 3.2.5;

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

(b) Bids, offers, or pricing information identifiable to a specific Qualified Scheduling Entity (QSE) or Resource. The Protected Information status of part of this information shall expire 60 days after the applicable Operating Day, as follows:

(i) Ancillary Service Offers by Operating Hour or Security-Constrained Economic Dispatch (SCED) interval for each Resource for all Ancillary Services submitted for the Day-Ahead Market (DAM) or Real-Time Market (RTM);

(ii) The quantity of Ancillary Service offered by Operating Hour or SCED interval for each Resource for all Ancillary Service submitted for the DAM or RTM; and

(iii) A Resource's Energy Offer Curve prices and quantities by Operating Hour or SCED interval. The Protected Information status of this information shall expire within seven days after the applicable Operating Day if required to be posted as part of paragraph (5) of Section 3.2.5 and within two days after the applicable Operating Day if required to be posted as part of paragraph (7) of Section 3.2.5;

(c) Status of Resources, including Outages, limitations, or scheduled or metered Resource data. The Protected Information status of this information shall expire as follows:

(i) For each Forced Outage, Maintenance Outage, or Forced Derate of a Generation Resource or Energy Storage Resource (ESR) that occurs during or extends into an Operating Day, the Protected Information status of the following information shall expire three days after the applicable Operating Day:

(A) The name and unit code of the Resource affected;

(B) The Resource's fuel type;

(C) The type of Outage or derate;

(D) The start date/time and the planned and actual end date/time;

(E) The Resource's applicable Seasonal net maximum sustainable rating;

(F) The available and outaged MW during the Outage or derate; and

(G) The entry in the "nature of work" field in the Outage Scheduler and any other information concerning the cause of the Outage or derate;

(ii) For each Resource Outage or Forced Derate that occurs during, or that extends into, any time period in which ERCOT has declared an Energy Emergency Alert (EEA), ERCOT may immediately disclose the information identified in paragraph (i) above to a state Governmental Authority, the office of the Governor of Texas, the office of the Lieutenant Governor of Texas, or any member of the Texas Legislature, if requested; and

(iii) For all other information, the Protected Information status shall expire 60 days after the applicable Operating Day;

(d) Current Operating Plans (COPs). The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(e) Ancillary Service Trades, Energy Trades, and Capacity Trades identifiable to a specific QSE or Resource. The Protected Information status of this information shall expire 180 days after the applicable Operating Day;

(f) Ancillary Service Schedules identifiable to a specific QSE or Resource. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

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

(f) Ancillary Service awards identifiable to a specific QSE or Resource. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(g) Dispatch Instructions identifiable to a specific QSE or Resource, except for Reliability Unit Commitment (RUC) commitments and decommitments as provided in Section 5.5.3, Communication of RUC Commitments and Decommitments. The Protected Information status of this information shall expire 180 days after the applicable Operating Day;

(h) Raw and Adjusted Metered Load (AML) data (demand and energy) identifiable to:

(i) A specific QSE or Load Serving Entity (LSE). The Protected Information status of this information shall expire 180 days after the applicable Operating Day; or

(ii) A specific Customer or Electric Service Identifier (ESI ID);

(i) Wholesale Storage Load (WSL) data identifiable to a specific QSE. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(j) Settlement Statements and Invoices identifiable to a specific QSE. The Protected Information status of this information shall expire 180 days after the applicable Operating Day;

(k) Number of ESI IDs identifiable to a specific LSE. The Protected Information status of this information shall expire 365 days after the applicable Operating Day;

(l) Information related to generation interconnection requests, to the extent such information is not otherwise publicly available. The Protected Information status of certain generation interconnection request information expires as provided in Section 1.3.1.4, Expiration of Protected Information Status;

(m) Resource-specific costs, design and engineering data, including such data submitted in connection with a verifiable cost appeal;

(n) Congestion Revenue Right (CRR) credit limits, the identity of bidders in a CRR Auction, or other bidding information identifiable to a specific CRR Account Holder. The Protected Information status of this information shall expire as follows:

(i) The Protected Information status of the identities of CRR bidders that become CRR Owners and the number and type of CRRs that they each own shall expire at the end of the CRR Auction in which the CRRs were first sold; and

(ii) The Protected Information status of all other CRR information identified above in item (n) shall expire six months after the end of the year in which the CRR was effective.

(o) Renewable Energy Credit (REC) account balances. The Protected Information status of this information shall expire three years after the REC Settlement period ends;

(p) Credit limits identifiable to a specific QSE;

(q) Any information that is designated as Protected Information in writing by Disclosing Party at the time the information is provided to Receiving Party except for information that is expressly designated not to be Protected Information by Section 1.3.1.2 or that, pursuant to Section 1.3.1.4, is no longer confidential;

(r) Any information compiled by a Market Participant on a Customer that in the normal course of a Market Participant's business that makes possible the identification of any individual Customer by matching such information with the Customer's name, address, account number, type of classification service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing record, or any other information that a Customer has expressly requested not be disclosed ("Proprietary Customer Information") unless the Customer has authorized the release for public disclosure of that information in a manner approved by the Public Utility Commission of Texas (PUCT). Information that is redacted or organized in such a way as to make it impossible to identify the Customer to whom the information relates does not constitute Proprietary Customer Information;

(s) Any software, products of software, or other vendor information that ERCOT is required to keep confidential under its agreements;

(t) QSE, Transmission Service Provider (TSP), and Distribution Service Provider (DSP) backup plans collected by ERCOT under the Protocols or Other Binding Documents;

[NPRR857: Replace item (t) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(t) QSE, Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), and Distribution Service Provider (DSP) backup plans collected by ERCOT under the Protocols or Other Binding Documents;

(u) Direct Current Tie (DC Tie) Schedule information. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(v) Any Texas Standard Electronic Transaction (TX SET) transaction submitted by an LSE to ERCOT or received by an LSE from ERCOT. This paragraph does not apply to ERCOT's compliance with:

(i) PUCT Substantive Rules on performance measure reporting;

(ii) These Protocols or Other Binding Documents; or

(iii) Any Technical Advisory Committee (TAC)-approved reporting requirements;

(w) Information concerning a Mothballed Generation Resource's probability of return to service and expected lead time for returning to service submitted pursuant to Section 3.14.1.9, Generation Resource Status Updates;

(x) Information provided by Entities under Section 10.3.2.4, Reporting of Net Generation Capacity;

(y) Alternative fuel reserve capability and firm gas availability information submitted pursuant to Section 6.5.9.3.1, Operating Condition Notice, Section 6.5.9.3.2, Advisory, and Section 6.5.9.3.3, Watch, and as defined by the Operating Guides;

(z) Non-public financial information provided by a Counter-Party to ERCOT pursuant to meeting its credit qualification requirements as well as the QSE's form of credit support;

(aa) ESI ID, identity of Retail Electric Provider (REP), and MWh consumption associated with transmission-level Customers that wish to have their Load excluded from the Renewable Portfolio Standard (RPS) calculation consistent with Section 14.5.3, End-Use Customers, and subsection (j) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy;

(bb) Emergency operations plans submitted pursuant to P.U.C. SUBST. R. 25.53, Electric Service Emergency Operations Plans;

(cc) Information provided by a Counter-Party under Section 16.16.3, Verification of Risk Management Framework;

(dd) Any data related to Load response capabilities that are self-arranged by the LSE or pursuant to a bilateral agreement between a specific LSE and its Customers, other than data either related to any service procured by ERCOT or non-LSE-specific aggregated data. Such data includes pricing, dispatch instructions, and other proprietary information of the Load response product;

(ee) Status of Settlement Only Generators (SOGs), including Outages, limitations, or scheduled or metered output data, except that ERCOT may disclose output data from an SOG as part of an extract or forwarded TX SET transaction provided to the LSE associated with the ESI ID of the Premise where the SOG is located. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

[NPRR829 and NPRR995: Replace applicable portions of paragraph (ee) above with the following upon system implementation:]

(ee) Status of Settlement Only Generators (SOGs) and Settlement Only Energy Storage System (SOESS), including Outages, limitations, schedules, metered output and withdrawal data, or data telemetered for use in the calculation of Real-Time Liability (RTL) as described in Section 16.11.4.3.2, Real-Time Liability Estimate, except that ERCOT may disclose metered output and withdrawal data from an SOG or SOESS as part of an extract or forwarded TX SET transaction provided to the LSE associated with the ESI ID of the Premise where the SOG is located. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(ff) Any documents or data submitted to ERCOT in connection with an Alternative Dispute Resolution (ADR) proceeding. The Protected Information status of this information shall expire upon ERCOT's issuance of a Market Notice indicating the disposition of the ADR proceeding pursuant to paragraph (1) of Section 20.9, Resolution of Alternative Dispute Resolution Proceedings and Notification to Market Participants, except to the extent the information continues to qualify as Protected Information pursuant to another paragraph of this Section 1.3.1.1;

(gg) Reasons for and future expectations of overrides to a specific Resource's High Dispatch Limit (HDL) or Low Dispatch Limit (LDL). The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(hh) Information provided to ERCOT under Section 16.18, Cybersecurity Incident Notification, except that ERCOT may disclose general information concerning a

Cybersecurity Incident in a Market Notice in accordance with paragraph (5) of Section 16.18 to assist Market Participants in mitigating risk associated with a Cybersecurity Incident;

(ii) Information disclosed in response to paragraphs (1)-(4) of the Natural Gas Pipeline Coordination section of Section 22, Attachment K, Declaration of Natural Gas Pipeline Coordination, submitted to ERCOT in accordance with Section 3.21, Submission of Declarations of Natural Gas Pipeline Coordination. The Protected Information status of Resource Outage information shall expire as provided in paragraph (1)(c) of Section 1.3.1.1; and

(jj) Information concerning weatherization activities submitted to, obtained by, or generated by ERCOT in connection with P.U.C. SUBST. R. 25.55, Weather Emergency Preparedness, if such information allows the identification of any Resource or Resource Entity.

1.3.1.2 Items Not Considered Protected Information

(1) Notwithstanding the definition of "Protected Information" in Section 1.3.1.1, Items Considered Protected Information, the following items are not Protected Information even if so designated:

(a) Data comprising Load flow cases, which may include estimated peak and off-peak Demand of any Load;

(b) Existence of Power System Stabilizers (PSSs) at each interconnected Generation Resource and PSS status (in service or out of service);

(c) Reliability Must-Run (RMR) Agreements;

(d) Studies, reports and data used in ERCOT's assessment of whether an RMR Unit satisfies ERCOT's criteria for operational necessity to support ERCOT System reliability but only if they have been redacted to exclude Protected Information under Section 1.3.1.1;

(e) Status of RMR Units;

(f) Black Start Agreements;

(g) Firm Fuel Supply Service (FFSS) awards;

(h) RMR Settlement charges and payments;

[NPRR885: Insert items (i) and (j) below upon system implementation and renumber accordingly:]

(i) Must-Run Alternative (MRA) Agreements;

(j) Settlement charges and payments for MRA Service;

(i) Within two Business Days of a request from a potential generating Facility for a full resource interconnection study, the county in which the Facility is located, Facility fuel type(s), Facility nameplate capacity, and anticipated Commercial Operations Date(s) and signed generation interconnection agreements; and

(j) Any other information specifically designated in these Protocols or in the PUCT Substantive Rules as information to be posted to the ERCOT website or Market Information System (MIS) Secure Area that is not specified as information that is subject to the requirements of Section 1.3, Confidentiality.

(2) Protected Information that Receiving Party is permitted or required to disclose or use under the Protocols or under an agreement between Receiving Party and a Disclosing Party does not cease to be regarded as Protected Information in all other circumstances not encompassed by these Protocols or such agreement by virtue of the permitted or required disclosure or use under these Protocols or such agreement.

1.3.1.3 Procedures for Protected Information

(1) The Receiving Party shall adopt procedures within its organization to maintain the confidentiality of all Protected Information. Such procedures must provide that:

(a) The Protected Information may be disclosed to the Receiving Party’s directors, officers, employees, representatives, and agents only on a “need to know” basis;

(b) The Receiving Party shall make its directors, officers, employees, representatives, and agents aware of Receiving Party’s obligations under this Section;

(c) If reasonably practicable, the Receiving Party shall cause any copies of the Protected Information that it creates or maintains, whether in hard copy, electronic format, or other form, to identify the Protected Information as such; and

(d) Before disclosing Protected Information to a representative or agent of the Receiving Party, the Receiving Party shall require a nondisclosure agreement with that representative or agent, except that a nondisclosure agreement shall not be required for the Receiving Party or Creating Party to disclose Protected Information to that party’s attorney. That nondisclosure agreement must contain confidentiality provisions substantially similar to the terms of this Section.

1.3.1.4 Expiration of Protected Information Status

(1) If PUCT Substantive Rules or other sections of the ERCOT Protocols require public posting (or posting to all Market Participants) of information identified as Protected Information in Section 1.3.1.1, Items Considered Protected Information, the Protected Information status of such information shall expire at the time such information is required to be posted.

(2) ERCOT shall make the following information available on the ERCOT website in a standard reporting format:

(a) Ancillary Service Obligation and Ancillary Service Supply Responsibility for each QSE. This information shall be made available 180 days after the Operating Day;

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

(a) Ancillary Service Obligation for each QSE. This information shall be made available 180 days after the Operating Day;

(b) Complete COP data for each QSE snapshot on each hour. This information shall be made available 60 days after the Operating Day; and

(c) In a separate report from item (b) above, complete COP data for each Resource for each update to that Resource's COP. This information shall be made available 60 days after the Operating Day.

[NPRR1035: Insert paragraph (d) below upon system implementation:]

(d) In a separate report, DC Tie Schedules by DC Tie for each 15-minute clock interval of the Operating Day for each update to that schedule. This information will include start time, stop time, DC Tie name, the scheduling QSE, Electronic Tag (e-Tag), and the MW flow (positive = export, negative = import). This information shall be made available 60 days after the Operating Day.

(3) ERCOT shall make available the AML for each QSE by LSE, by Load Zone and by Settlement Interval, from the True-Up settlement. This data shall be made available within two Business Days of the 180 day expiration of Protected Information status. Data for the posting will remain accessible for six months after such data are posted.

(4) The Protected Information status of information related to generation interconnection requests expires once ERCOT receives a request from an Interconnecting Entity (IE) for

a Full Interconnection Study (FIS), except that information described in item (1)(m) of Section 1.3.1.1 shall remain Protected Information.

(5) Upon the expiration of the Protected Information status of any data specified in Section 1.3.1.1, which does not have specific posting requirements, that data must be made available to the extent required under Section 12, Market Information System.

(6) Information that is no longer Protected Information, but not posted, including Dispatch Instructions, is available on request under the ERCOT Request for Records and Information Policy. Requested information must be provided within a reasonable timeframe. For Dispatch Instructions, the information may be requested with respect to a specific Resource, where applicable, and by service type and Settlement Interval or as integrated over each Settlement Interval for Dispatch Instructions with sub-Settlement Interval frequency.

1.3.2 ERCOT Critical Energy Infrastructure Information

(1) ERCOT, the IMM, or any Market Participant may not disclose ECEII to any other Entity except as specifically permitted in this Section and in these Protocols.

(2) For purposes of subsection (e) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance, ECEII constitutes Protected Information that shall be protected from public disclosure, except as otherwise provided therein and in these Protocols.

(3) ERCOT may classify information as ECEII, regardless of whether the submitter has designated the information as ECEII or has otherwise requested ECEII status for the information, upon determining that the information is included on the list of items considered ECEII in Section 1.3.2.1, Items Considered ERCOT Critical Energy Infrastructure Information, or otherwise meets the definition of ECEII set forth in Section 2.1, Definitions. Upon determining that information for which ECEII status has not been requested should be designated as ECEII, ERCOT shall notify the submitter. A determination by ERCOT to classify information as ECEII is subject to review by the PUCT as set forth in Section 1.3.8, Commission Review of ERCOT Determinations Regarding Protected Information or ERCOT Critical Energy Infrastructure Information Status.

(4) Different types of ECEII may involve different levels of security risk. In its discretion, ERCOT may restrict Market Participant access to ECEII created or received by ERCOT that poses a high level of security risk, provided that ERCOT shall disclose such information to any Transmission and/or Distribution Service Provider (TDSP) upon request and may disclose such information to any other Market Participant that ERCOT determines has a legitimate reliability-based need for that information, subject to the requirements and restrictions of this Section 1.3, Confidentiality. If ERCOT determines that ECEII that is required to be posted on the ERCOT website or MIS Secure Area pursuant to these Protocols or an Other Binding Document poses a high level of security risk, ERCOT shall remove such information from the ERCOT website or MIS Secure

Area notwithstanding such posting requirement, and shall promptly submit a Revision Request to remove the requirement to post such information. If the Revision Request is withdrawn or rejected, ERCOT shall restore any information required to be posted to the MIS that had been removed pursuant to this paragraph.

(5) A Receiving Party or Creating Party of ECEII shall adopt procedures to ensure that ECEII is securely maintained and the organization's internal distribution of ECEII is reasonably restricted to appropriate individuals.

(6) A Receiving Party or Creating Party may not knowingly use ECEII for any illegal purpose.

(7) Before disclosing ECEII to a representative or agent of the Receiving Party or Creating Party, the Receiving Party or Creating Party shall require a nondisclosure agreement with that representative or agent, except that a nondisclosure agreement shall not be required for the Receiving Party or Creating Party to disclose ECEII to that party's attorney.

1.3.2.1 Items Considered ERCOT Critical Energy Infrastructure Information

(1) ECEII includes but is not limited to the following, so long as such information has not been disclosed to the public through lawful means:

(a) Detailed ERCOT System Infrastructure locational information, such as Global Positioning System (GPS) coordinates;

(b) Information that reveals that a specified contingency or fault results in instability, cascading or uncontrolled separation;

(c) Studies and results of simulations that identify cyber and physical security vulnerabilities of ERCOT System Infrastructure;

(d) Black Start Service (BSS) test results, individual Black Start Resource start-up procedures, cranking paths, and ERCOT and individual TSP Black Start plans;

(e) Information contained in Section 1.B. and Exhibit 1 to the Standard Form Black Start Agreement (Section 22, Attachment D, Standard Form Black Start Agreement), except for the Hourly Standby Price, Notice, and Certification sections. This includes, without limitation, the following information that could identify a Generation Resource as a Black Start Resource:

(i) Resource name;

(ii) Resource ID;

(iii) County where the Resource is located;

(iv) Interconnected substation;

(v) Resource MW capability; and

(vi) Tested next start units;

(f) Emergency operations plans, including ERCOT's emergency operations plan and any emergency operations plan submitted to ERCOT pursuant to any PUCT rule or North American Electric Reliability Corporation (NERC) Reliability Standard;

(g) Detailed ERCOT Transmission Grid maps, other than maps showing only small portions of the ERCOT Transmission Grid such as those included in Regional Planning Group (RPG) Project ERCOT Independent Review reports;

(h) Detailed diagrams or information about connectivity between ERCOT's and other Entities' computer and telecommunications systems, such as internet protocol (IP) addresses, media access control (MAC) addresses, network protocols, and ports used; and

(i) Any information that is clearly designated as ECEII in writing by the Disclosing Party at the time the information is provided to Receiving Party, subject to the procedures set forth in paragraph (3) of Section 1.3.2.2, Submission of ERCOT Critical Energy Infrastructure Information to ERCOT.

1.3.2.2 Submission of ERCOT Critical Energy Infrastructure Information to ERCOT

(1) ECEII submitted to ERCOT shall be clearly labeled on the cover page and pages or portions of the information or otherwise clearly identify the information for which ECEII treatment is claimed, to the extent practicable. The submission of information labeled as ECEII constitutes a representation by the submitter that the information is ECEII as defined in these Protocols. The submitter shall also segregate those portions of the information that contain ECEII wherever feasible.

(2) Failure to request ECEII treatment or failure to conspicuously label or segregate ECEII information submitted to ERCOT in accordance with paragraph (1) above may result in non-ECEII treatment of the information by ERCOT and release of the information to the public.

(3) For any submission of information asserted to be ECEII, ERCOT may, at any time following the submission, request that the submitter provide a written justification for such treatment. The submitter shall provide such a justification, if any, within five Business Days. The justification must explain how the information, or any portion of the information, qualifies as ECEII, as such term is defined in Section 2.1, Definitions, and must identify any law, regulation, or order that protects the information, or any portion of the information, from disclosure. The request shall also include a statement of how long the ECEII designation should apply to the information and support for the period proposed. ERCOT shall consider any submitted justification before determining whether the information qualifies as ECEII. ERCOT shall not disclose or permit disclosure of any information protected from disclosure pursuant to law, regulation, or order. ERCOT

shall notify the submitter of its determination within five Business Days after receiving the submission. ERCOT shall continue to treat as ECEII information originally claimed to be ECEII for five Business Days following the date ERCOT notified the submitter of its determination. A determination by ERCOT not to classify information as ECEII is subject to review by the PUCT as set forth in Section 1.3.8, Commission Review of ERCOT Determinations Regarding Protected Information or ERCOT Critical Energy Infrastructure Information Status.

1.3.3 RESERVED

1.3.4 Protecting Disclosures to the PUCT, CFTC, Governmental Cybersecurity Oversight Agencies, and Other Governmental Authorities

(1) Any disclosure that a Receiving Party makes to the PUCT must be made under applicable PUCT rules. For any disclosure of Protected Information or ECEII to the PUCT outside the scope of subsection (e) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance, the Receiving Party must file that Protected Information or ECEII as confidential pursuant to subsection (d) of P.U.C. PROC. R. 22.71, Filing of Pleadings, Documents, and Other Materials.

(2) For any disclosure of Protected Information to the Commodity Futures Trading Commission (CFTC) pursuant to a request made under the CFTC's authority in accordance with the Commodity Exchange Act and the CFTC's regulations, ERCOT, as the Receiving Party, shall timely submit to the CFTC a written request for confidential treatment of the Protected Information in accordance with the applicable provisions of the Commodity Exchange Act and CFTC regulations.

(3) Before making a disclosure of Protected Information involving a Cybersecurity Incident to a Governmental Cybersecurity Oversight Agency or delegated entity for the purpose of ensuring the safety and/or security of the ERCOT System or ERCOT's ability to perform functions of an independent organization under the Public Utility Regulatory Act (PURA), ERCOT, as the Receiving Party, will obtain adequate assurance from such Governmental Cybersecurity Oversight Agency that it will maintain the confidentiality of Protected Information.

(4) Before making a disclosure under order of a Governmental Authority other than the PUCT and the CFTC, the Receiving Party or Creating Party shall seek a protective order from such Governmental Authority to protect the confidentiality of Protected Information or ECEII.

(5) Before making a disclosure under order of a Governmental Authority other than the PUCT, CFTC, or a Governmental Cybersecurity Oversight Agency to ensure the safety and/or security of the ERCOT System or ERCOT's ability to perform the functions of an independent organization under PURA, the Receiving Party shall seek a protective order from such Governmental Authority to protect the confidentiality of Protected Information.

(6) Nothing in this Section authorizes any disclosure of Protected Information or ECEII; this Section merely creates requirements on disclosures that are authorized under other sections of these Protocols.

1.3.5 Notice Before Permitted Disclosure

(1) Before making any disclosure under Section 1.3.6, Exceptions, the Receiving Party shall promptly notify the Disclosing Party in writing and, with the exception of information disclosed pursuant to paragraph (3) of Section 1.3.6, shall assert confidentiality and take reasonable steps to cooperate with the Disclosing Party in seeking to protect the Protected Information or ECEII from disclosure by confidentiality agreement, protective order, aggregation of information, or other reasonable measures. Notwithstanding the foregoing, ERCOT is not required to provide notice to the Disclosing Party of disclosures made under items (1)(b) or (1)(l) of Section 1.3.6.

(2) If the Disclosing Party is not also the Creating Party, upon receipt of the notice required by paragraph (1) above, the Disclosing Party shall promptly notify the Creating Party, unless, after making reasonable efforts, the Disclosing Party is unable to identify the Creating Party.

1.3.6 Exceptions

(1) The Receiving Party or Creating Party may, without violating Section 1.3, Confidentiality, disclose Protected Information or ECEII:

(a) To governmental officials, Market Participants, the public, or others as required by any law, regulation, or order, or by these Protocols, but any Receiving Party or Creating Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII by protective order, by aggregating information, or otherwise if reasonably possible; or

(b) If ERCOT is the Receiving Party or Creating Party and disclosure to the PUCT, Reliability Monitor or IMM of the Protected Information or ECEII is required by ERCOT pursuant to applicable Protocol, law, regulation, or order; or

(c) For Protected Information, if the Disclosing Party has given its prior written consent to the disclosure, which consent may be given or withheld in Disclosing Party’s sole discretion; or

(d) For Protected Information, if the Protected Information, before it is furnished to the Receiving Party, has been disclosed to the public through lawful means; or

(e) For Protected Information, if the Protected Information, after it is furnished to the Receiving Party, is disclosed to the public other than as a result of a breach by the Receiving Party of its obligations under Section 1.3; or

(f) If reasonably deemed by the disclosing Receiving Party to be required to be disclosed in connection with a dispute between the Receiving Party and the Disclosing Party, but the disclosing Receiving Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII by protective order, by aggregating information, or otherwise if reasonably possible; or

(g) To a TSP or DSP engaged in the ERCOT Transmission Grid or Distribution System planning and operating activities, provided that the TSP or DSP has executed a confidentiality agreement with ERCOT with requirements substantially similar to those in Section 1.3. ERCOT shall post on the ERCOT website a list of all TSPs and DSPs that have confidentiality agreements in effect with ERCOT; or

(h) For Protected Information, to a vendor or prospective vendor of goods and services to ERCOT or a TDSP, so long as such vendor or prospective vendor:

(i) Is not a Market Participant, except that ERCOT or the TDSP may disclose Protected Information to a vendor or prospective vendor that is also an Independent Market Information System Registered Entity (IMRE) to the extent appropriate for the vendor to carry out its responsibilities in such capacity or for the prospective vendor to engage in commercial discussions; and

(ii) Has executed a confidentiality agreement with requirements at least as restrictive as those in Section 1.3; or

(i) For ECEII, to a vendor or prospective vendor of goods and services, so long as such vendor or prospective vendor has executed a confidentiality agreement with requirements at least as restrictive as those in Section 1.3; or

(j) To the North American Electric Reliability Corporation (NERC) or the NERC Regional Entity if required for compliance with any applicable NERC or NERC Regional Entity requirement, but any Receiving Party or Creating Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII as reasonably possible; or

(k) To ERCOT and its consultants, the IMM, the Reliability Monitor, and members of task forces and working groups of ERCOT, if engaged in performing analysis of abnormal system conditions, disturbances, unusual events, and abnormal system performance, or engaged in tasks involving ECEII for support of the ERCOT Transmission Grid. Notwithstanding the foregoing sentence, task forces and working groups may not receive Ancillary Service Offer prices or other competitively sensitive price or cost information before expiration of its status as Protected Information, and each member of a task force or working group shall execute a confidentiality agreement with requirements substantially similar to those in Section 1.3, prior to receiving any Protected Information or ECEII. Data to be disclosed under this exception to task forces and working groups must be limited to clearly defined periods surrounding the relevant conditions, events, or performance under review and must be limited in scope to information pertinent to the condition or events under review and may include the following:

(i) QSE Ancillary Service awards and deployments, in aggregate and by type of Resource;

(ii) Resource facility availability status, including the status of switching devices, auxiliary loads, and mechanical systems that had a material impact on Resource facility availability or an adverse impact on the transmission system operation;

(iii) Individual Resource information including Base Points, maximum/minimum generating capability, droop setting, real power output, and reactive output;

(iv) Resource protective device settings and status;

(v) Data from COPs;

(vi) Resource Outage schedule information; and

(vii) BSS test results and ERCOT's Black Start plan, including individual Black Start Resource start-up procedures, cranking paths, and individual TSP Black Start plans;

(l) To the CFTC if requested from ERCOT by the CFTC as part of an investigation or regulatory inquiry authorized pursuant to the Commodity Exchange Act and the CFTC's regulations or if required to be submitted to the CFTC pursuant to any other law, provided that ERCOT, as the Receiving Party or Creating Party, must timely submit a written request for confidential treatment in accordance with the CFTC's regulations or other applicable law; or

(m) To a Governmental Cybersecurity Oversight Agency regarding a Cybersecurity Incident, if ERCOT is the Receiving Party, and disclosure of Protected Information is made to a Governmental Cybersecurity Oversight Agency or delegated entity for the purpose of ensuring the safety and/or security of the ERCOT System or ERCOT's ability to perform the functions of an independent organization under PURA.

(2) Protected Information may not be disclosed to other Market Participants prior to ten days following the Operating Day under review.

(3) ERCOT may disclose, and may authorize a Receiving Party or Creating Party to disclose, ECEII to the public or to any person under the provisions of this paragraph, except for ECEII otherwise protected from disclosure pursuant to law, regulation, or order.

(a) ERCOT may propose to disclose ECEII that is not otherwise protected from disclosure pursuant to law, regulation, or order. Any Receiving Party or Creating Party other than ERCOT may request ERCOT authorization to disclose such ECEII.

(i) ERCOT may propose to disclose ECEII that is not otherwise protected from disclosure pursuant to law, regulation, or order if it determines that the public benefit of the proposed disclosure of ECEII outweighs the potential harm resulting from the disclosure. ERCOT shall issue a Market Notice regarding ERCOT's intent to disclose the ECEII, subject to objection as further provided in paragraph (c) below.

(ii) A request by a Receiving Party or Creating Party other than ERCOT for authorization to disclose ECEII shall be submitted by e-mail to ERCOT's General Counsel. If the ECEII is not otherwise protected from disclosure pursuant to law, regulation, or order, and ERCOT determines that the public benefit of the proposed disclosure of ECEII outweighs the potential harm resulting from the disclosure, ERCOT shall issue a Market Notice authorizing the ECEII to be disclosed, subject to objection as further provided in paragraph (c) below. ERCOT shall make such a determination no later than five Business Days following the date it receives the request.

(b) The Market Notice issued pursuant to paragraph (a)(i) or (ii) above shall identify the ECEII to be disclosed; the party requesting the disclosure; the public benefit justifying the proposed disclosure; the date on which the information may be disclosed, which shall be no sooner than five Business Days following the date of the Market Notice; and, if the proposed disclosure is not to the public, the persons to whom ECEII would be disclosed. The authorization shall be effective unless a Market Participant submits an objection pursuant to paragraph (c) below.

(c) Any Market Participant may submit written objections to the proposed disclosure. Such objections shall be submitted by e-mail to ERCOT's General Counsel no later than the end of the fourth Business Day following the issuance of the Market Notice described in paragraph (b) above. Failure to object to the proposed allowance of ECEII disclosure pursuant to this paragraph shall constitute a waiver of any such objection for all purposes. ERCOT shall provide notice of the objection to the party requesting authorization to disclose ECEII no later than the end of the Business Day following receipt of the objection. The party requesting authorization to disclose ECEII shall not disclose the ECEII if it has been notified of any objection pursuant to this paragraph unless and until ERCOT issues a second Market Notice authorizing disclosure, as provided in paragraph (d) below.

(d) If one or more objections to disclosure is submitted pursuant to paragraph (c) above, ERCOT shall issue a second Market Notice describing each such objection and stating whether the objection affects ERCOT's determination as to the proposed disclosure of ECEII. If ERCOT determines that the ECEII should still be disclosed notwithstanding these objections, the second Market Notice shall establish the date on which the ECEII may be disclosed, which shall be no sooner than the fifth Business Day following the issuance of the second Market Notice. ERCOT's determination in the second Market Notice is a final decision that may be challenged at the PUCT without using the processes described in Section 20, Alternative Dispute Resolution Procedure. If ERCOT authorizes a non-public disclosure of ECEII, the party disclosing the ECEII shall require each recipient of ECEII to enter into a nondisclosure agreement that includes the restrictions against disclosure described in Section 1.3.2, ERCOT Critical Energy Infrastructure Information, as a condition for obtaining the ECEII.

(e) Notwithstanding anything in this Section, ERCOT may disclose ECEII to any federal, state or local government official without issuing a Market Notice if ERCOT determines that such disclosure is necessary to facilitate the government official's public duties and that the delay associated with providing the Notice otherwise required by this paragraph (3) would impair that government official's ability to take action to address a public emergency. As soon as practicable, but no later than 24 hours following the disclosure:

(i) ERCOT shall provide Notice to the Disclosing Party and all Market Participants materially impacted by the disclosure; and

(ii) ERCOT shall issue a Market Notice describing the disclosure, unless ERCOT determines that such a Notice could jeopardize public safety or welfare, in which case no Notice is required.

(iii) Each Disclosing Party, other than ERCOT, shall provide Notice to each Creating Party whose information has been disclosed pursuant to this paragraph (e).

(f) Notwithstanding anything in this Section, any Receiving Party or Creating Party other than ERCOT may disclose ECEII to any federal, state or local government official without requesting prior authorization from ERCOT if the Receiving Party or Creating Party determines that such disclosure is necessary to facilitate the government official's public duties and that the delay associated with requesting prior ERCOT authorization as otherwise required by this paragraph (3) would impair that government official's ability to take action to address a public emergency.

(i) The Receiving Party or Creating Party shall provide Notice to ERCOT and all Market Participants materially impacted by the disclosure as soon as practicable, but no later than 24 hours following the disclosure.

(ii) ERCOT shall issue a Market Notice describing the disclosure as soon as practicable, but no later than 24 hours following receipt of notice from the Receiving Party or Creating Party, unless ERCOT determines that such a

Notice could jeopardize public safety or welfare, in which case no Notice is required.

1.3.7 Specific Performance

(1) It will be impossible or very difficult to measure in monetary terms the damages that would accrue due to any breach by Receiving Party of Section 1.3, Confidentiality, or any failure to perform any obligation contained in Section 1.3 and, for that reason, among others, a Disclosing Party affected by a disclosure or threatened disclosure is entitled to specific performance of Section 1.3. In the event that a Disclosing Party institutes any proceeding to enforce any part of Section 1.3, the affected Receiving Party, by entering any agreement incorporating these Protocols, now waives any claim or defense that an adequate remedy at law exists for such a breach.

1.3.8 Commission Review of ERCOT Determinations Regarding Protected Information or ERCOT Critical Energy Infrastructure Information Status

(1) A determination by ERCOT that one or more items are or are not Protected Information or ECEII, or that the public benefit of the proposed disclosure of ECEII outweighs the potential harm resulting from the disclosure, is a final decision that may be challenged at the PUCT without using the processes described in Section 20, Alternative Dispute Resolution Procedure. Any Entity materially affected by ERCOT's determination shall, as a condition for seeking relief at the PUCT, notify ERCOT's General Counsel no later than 1700 Central Prevailing Time (CPT) on the date five Business Days following the date ERCOT notified the submitter of its determination and shall file any complaint against ERCOT no later than 35 days following the date of the final decision, pursuant to P.U.C. PROC. R. 22.251, Review of Electric Reliability Council of Texas (ERCOT) Conduct. If an Entity materially affected by ERCOT's determination notifies ERCOT that it is challenging ERCOT's determination and files a complaint no later than 35 days following the ERCOT determination, ERCOT shall not disclose the information until the PUCT issues a final order authorizing such release.

1.4 Operational Audit

1.4.1 Materials Subject to Audit

(1) ERCOT's records and documentation pertaining to its operation as the certified Independent Organization for the ERCOT Region are subject to audit in the manner prescribed herein. The rights of Market Participants to audit ERCOT are limited to the provisions in Section 1.4, Operational Audit.

1.4.2 ERCOT Finance and Audit Committee

(1) The ERCOT Board shall have overall audit responsibility for ERCOT. The ERCOT Board may fulfill audit responsibilities itself or delegate them to the ERCOT Finance and Audit (F&A) Committee. Upon delegation, the ERCOT F&A Committee shall make recommendations to the ERCOT Board or directly appoint an external independent certified public accounting firm or firms ("Appointed Firm") to conduct certain audits. For audits performed by an Appointed Firm, the ERCOT F&A Committee shall directly approve the initiation, scheduling, and reporting of such audits or make recommendations to the ERCOT Board. The ERCOT F&A Committee may also direct the ERCOT Internal Audit Department to conduct certain audits. The ERCOT F&A Committee shall approve an annual audit plan for the ERCOT Internal Audit Department.

1.4.3 Operations Audit

1.4.3.1 Audits to Be Performed

(1) At least annually, an Appointed Firm shall perform a System and Organization Control (SOC) audit of ERCOT regarding ERCOT's market Settlements operations.

(2) The ERCOT Internal Audit Department will conduct audits of the following on a periodic basis no less than once every three years:

(a) Compliance with ERCOT's policies that prohibit employees from:

(i) Being involved in business decisions where the individual stands to gain or lose personally from the decision;

(ii) Having a direct financial interest in a Market Participant;

(iii) Serving in an advisory, consulting, technical or management capacity for any business organization that does significant business with ERCOT (other than through service on ERCOT committees); and

(iv) Accepting any gifts or entertainment of significant value from employees or representatives of any Market Participant doing business in ERCOT. Such gifts and entertainment shall not exceed the limits specified in ERCOT's Code of Conduct and Ethics Corporate Standard and other applicable policies.

(b) Whether ERCOT is operating in compliance with the confidentiality and Protected Information provisions of these Protocols;

(c) Verification that ERCOT, in its administration of these Protocols, is operating independently of control by any Market Participant or group of Market Participants; and

(d) Any audit required by the Public Utility Commission of Texas (PUCT).

1.4.3.2 Material Issues

(1) The audits performed under Section 1.4.3.1, Audits to be Performed, may also include material issues raised by ERCOT Members and/or Market Participants if:

(a) Such issues have been presented to TAC, approved by TAC and approved by the ERCOT F&A Committee for inclusion in the audit scope; or

(b) Such issues are part of a random sample of complaints selected by the auditors for review, and affected Market Participants have agreed in writing to the examination of their related information in the compliance audit.

(2) Members and Market Participants shall send any requests regarding such issues to the ERCOT TAC Chairperson designee identified on the MIS for inclusion on the TAC agenda.

1.4.4 Audit Results

(1) Unless a longer time frame is reasonably necessary (e.g., for the market Settlements SOC audit, which is performed over a significant period of time), each audit report will be prepared and finalized no later than four months after the initiation of the audit. Results of all audits performed pursuant to this Section shall be reported to the ERCOT F&A Committee. These audits will be filed with the PUCT in accordance with PUCT Rules. ERCOT may file an audit as confidential and Protected Information in order to protect Protected Information and other confidential or sensitive information therein. Findings and recommended actions identified as a result of an audit will be reviewed by the ERCOT F&A Committee. The results of the audits required by this Section and the recommended actions to be taken by ERCOT shall be provided to ERCOT Members and Market Participants upon request to the extent these items do not contain Protected Information or other confidential or sensitive information.

1.4.5 Availability of Records

(1) Subject to the requirements of Section 1.4.6, Confidentiality of Information, ERCOT will provide the ERCOT Internal Audit Department, and/or the Appointed Firm and any other staff augmentation resources full and complete access to all financial books, cost statements, accounting records, and all documentation pertaining to the requirements of the specific audits being performed. ERCOT will retain records relating to audits until the records retention requirements of ERCOT are satisfied; or until the audit issues are fully resolved, whichever is the later. Such retention shall be a term of not less than four years and not be required for more than seven years. This Section 1.4, Operational Audit, is not intended to require ERCOT to create any new records, reports, studies, or evaluations.

1.4.6 Confidentiality of Information

(1) All Protected Information as defined in these Protocols obtained by the Appointed Firm or other staff augmentation resources through any audits will remain strictly confidential. To retain control of Protected Information, ERCOT will require that each Appointed Firm and each individual staff augmentation resource either (i) sign a confidentiality agreement with terms substantially similar to the terms of Section 1.3, Confidentiality, above before being allowed access to any ERCOT records or documentation; or (ii) observe the Appointed Firm's internal confidentiality policies and procedures, whichever is acceptable to ERCOT's Legal Department but is no less stringent than the terms of Section 1.3. Audit reports and/or results provided to Market Participants or ERCOT Members shall not contain any Protected Information.

1.5 ERCOT Fees and Charges

(1) Fees and charges to Market Participants for use of the ERCOT scheduling, settlement, registration, and other related systems and equipment are set forth in these Protocols. The ERCOT Board may adopt additional fees and charges as reasonably necessary to cover the additional costs of such systems and equipment. Market Participants are responsible for all such applicable fees and charges. ERCOT shall post a schedule of ERCOT fees and charges on the ERCOT website within two Business Days of change.

1.6 Open Access to the ERCOT Transmission Grid

1.6.1 Overview

(1) Open access to the ERCOT Transmission Grid must be provided to all Eligible Transmission Service Customers by Transmission Service Providers (TSPs) and ERCOT under these Protocols and the Public Utility Commission of Texas (PUCT) Substantive Rules, Chapter 25, Substantive Rules Applicable to Electric Service Providers, Subchapter I, Transmission and Distribution.

1.6.2 Eligibility for Transmission Service

(1) Transmission Service is available to all Eligible Transmission Service Customers. Energy may be transmitted and Ancillary Service may be provided on behalf of an Eligible Transmission Service Customer through the ERCOT System only through a QSE.

1.6.3 Nature of Transmission Service

(1) Transmission Service allows all Eligible Transmission Service Customers to deliver and receive Energy using the Transmission Facilities of all of the Transmission Service Providers in ERCOT under PUCT Substantive Rules.

1.6.4 Payment for Transmission Access Service

(1) ERCOT may not collect Transmission Access Service fees for the TSPs' cost of service. ERCOT shall provide volumetric data, pursuant to Section 9, Settlement and Billing, to the TSPs so that the TSPs can calculate their Transmission access fees. ERCOT's collection and settlement process associated with ERCOT's scheduling and deployment of Ancillary Service is addressed separately in these Protocols.

1.6.5 Interconnection of New or Existing Generation

(1) Interconnection of new Generation Resources or Settlement Only Generators (SOGs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents.

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

(1) Interconnection of new Generation Resources, Settlement Only Generators (SOGs), or Settlement Only Energy Storage Systems (SOESSs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents.

(2) For existing Generation Resources and SOGs which connect to a new Point of Interconnection (POI) or which utilize more than one POI to the ERCOT Transmission Grid, any Protocol or Other Binding Document requirements applicable to Generation Resources and SOGs which are based upon the execution date of the Standard Generation Interconnection Agreement (SGIA) shall be applied to the date of the first executed SGIA with the following exceptions:

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

(2) For existing Generation Resources, SOGs, and SOESSs which connect to a new Point of Interconnection (POI) or which utilize more than one POI to the ERCOT Transmission Grid, any Protocol or Other Binding Document requirements applicable to Generation Resources, SOGs, and SOESSs which are based upon the execution date of the Standard Generation Interconnection Agreement (SGIA) shall be applied to the date of the first executed SGIA with the following exceptions:

(a) For a new POI, existing Generation Resources and Settlement Only Transmission Self-Generators (SOTSGs) shall comply with the requirements in Section 3.15, Voltage Support, and Nodal Operating Guide Section 2.9, Voltage Ride-Through Requirements for Generation Resources, based upon the execution date of the most recent SGIA.

(b) For more than one POI, existing Generation Resources and SOTSGs shall comply with the requirements in Section 3.15 and Nodal Operating Guide Section 2.9 based upon the execution date of the SGIA relative to the POI where the Generation Resource is electrically connected.

(3) When a Municipally Owned Utility (MOU) or Electric Cooperative (EC) transferring Load into the ERCOT System owns a generation unit currently serving the transferring Load in a non-ERCOT Control Area and seeks to interconnect the generation unit to the ERCOT Transmission Grid in conjunction with the Load transfer, the interconnection will be subject to the requirements in paragraph (1) above; however, if the Protocols, Planning Guide, Nodal Operating Guide or Other Binding Documents set forth an alternate requirement for Generation Resources or SOGs that were installed, connected, operating, or had an SGIA executed before a specified date, then ERCOT, in its sole discretion, may apply the alternate requirement to the MOU's or EC's generation unit, subject to the following:

(a) The generation unit must have been operating in the non-ERCOT Control Area on or before the date specified in the Protocol, Planning Guide, Nodal Operating Guide or Other Binding Document provision that sets forth the alternate requirement;

(b) The generation unit has not undergone a modification pursuant to paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, subsequent to the specified date from paragraph (3) above;

(c) The MOU or EC must submit a written request to ERCOT that identifies the alternate requirement(s) it seeks to have applied and explains why compliance with the requirement(s) applicable to new Generation Resources or SOGs is not feasible at a reasonable cost; and

(d) The MOU or EC must demonstrate to ERCOT's satisfaction through interconnection or similar studies that allowing the generation unit to comply with the alternate requirement will not create a risk to the reliability of the ERCOT System.

1.7 Rules of Construction

(1) Capitalized terms and acronyms used in the Protocols have the meanings set out in Section 2, Definitions and Acronyms, of these Protocols or the meanings expressly set out in another Section of the Protocols. If a capitalized term or acronym is defined in both Section 2, and another Section of these Protocols, then the definition in that other

Section controls the meaning of that term or acronym in that Section, but the definition in Section 2, controls in all other Sections of the Protocols; and

(2) In these Protocols, unless the context clearly otherwise requires:

(a) The singular includes the plural and vice versa;

(b) The present tense includes the future tense, and the future tense includes the present tense;

(c) Words importing any gender include the other gender;

(d) The words "including," "includes," and "include" are deemed to be followed by the words "without limitation;"

(e) The word "shall" denotes a duty;

(f) The word "will" denotes a duty, unless the context denotes otherwise;

(g) The word "must" denotes a condition precedent or subsequent;

(h) The word "may" denotes a privilege or discretionary power;

(i) The phrase "may not" denotes a prohibition;

(j) Reference to a Section, Attachment, Exhibit, or Protocol means a Section, Attachment, Exhibit, or provision of these Protocols;

(k) References to any statutes, regulations, tariffs, or these Protocols are deemed references to such statute, regulation, tariff, or Protocol as it may be amended, replaced, or restated from time to time;

(l) Unless expressly stated otherwise, references to agreements and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent that the amendments and other modifications are not prohibited by these Protocols;

(m) References to persons or Entities include their respective successors and permitted assigns and, for governmental Entities, Entities succeeding to their respective functions and capacities;

(n) References to "writing" include printing, typing, lithography, and other means of reproducing words in a tangible visible form;

(o) Any reference to a day, week, month, or year is to a calendar day, week, month, or year unless otherwise noted; and

(p) Any reference to time is to Central Prevailing Time; the 24-hour clock is used unless otherwise noted.

(q) Any reference to dollars is U.S. currency dollars unless otherwise noted.

(r) All Settlement calculations are in dollars (USD), unless otherwise noted.

(s) Any reference to energy is electrical energy, unless otherwise noted.

(3) These provisions apply to giving notice under the Protocols:

(a) Whenever these Protocols require an Entity to send a notice to another Entity and do not specify the method by which that notice should be sent, then the notice may be sent by:

(i) Hand-delivery:

(ii) Electronic mail;

(iii) Facsimile transmission;

(iv) Overnight delivery service (e.g., Federal Express, DHL or similar service) that requires a signed receipt;

(v) The Messaging System or other electronic means provided for by these Protocols; or

(vi) U.S. Mail, first class postage prepaid, registered (or certified) mail, return receipt requested, properly addressed.

(b) Notice by facsimile, electronic mail, the Messaging System, or other electronic means provided for by these Protocols is considered received when sent unless transmitted after 5:00 p.m. local time of the recipient or on a non-Business Day, in which case it is considered received one Business Day after it was sent.

(c) Notice by overnight delivery service that requires a signed receipt is considered received on the day that it was received.

(d) Notice by U.S. Mail is considered received three days after the date it was deposited in the U.S. Mail, first class postage prepaid, registered (or certified) mail, return receipt requested, properly addressed.

(e) For any notice sent by facsimile or electronic mail, the sender must promptly confirm the notice, in writing, by delivering the notice by:

(i) U.S. Mail, first class postage prepaid, registered (or certified) mail, return receipt requested, properly addressed;

(ii) Overnight delivery service requiring a signed receipt; or

(iii) Hand-delivery.

(f) If the Protocols require notice to a registered Market Participant by ERCOT, ERCOT must send the notice to the then-current Authorized Representative, if any, for the Market Participant as set forth in the Market Participant's Application for Registration on file with ERCOT or another representative designated in writing by the Authorized Representative for the purpose of receiving communications from ERCOT.

(g) When the Protocols require a notice to be in writing, sending it by electronic mail, the Messaging System, or other electronic means satisfies the requirement that the notice be in writing.

(4) Nothing in these Protocols may be construed to grant any jurisdiction or authority to NERC or FERC that they do not otherwise have.

1.8 Effective Date

(1) Provisions of these Protocols approved through the process set forth in Section 21, Revision Request Process, but not implemented until a specified later date or in accordance with other specified prerequisites to implementation, must be set forth, and the approved but not yet implemented provision must be set forth in boxes within the Protocols.

ERCOT Nodal Protocols

Section 2: Definitions and Acronyms

December 9, 2022

2 DEFINITIONS AND ACRONYMS

The list of acronyms is at the end of this Definitions Section.

2.1 DEFINITIONS

Definitions are supplied for terms used in more than one Section of the Protocols. If a term is used in only one Section, it is defined there at its earliest usage.

LINKS TO DEFINITIONS:

A, B, C, D, E, F, G, H, I, J, K, L, M, N, O, P, Q, R, S, T, U, V, W, X, Y, Z;

List of Acronyms

A

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Adjusted Metered Load (AML)

Retail Load usage data that has been adjusted for Unaccounted for Energy (UFE), Transmission Losses, Distribution Losses, and Direct Current Tie (DC Tie) exports (except for the Oklaunion Exemption).

[NPRR1054: Replace the above definition "Adjusted Metered Load (AML)" with the following upon system implementation:]

Adjusted Metered Load (AML)

Retail Load usage data that has been adjusted for Unaccounted for Energy (UFE), Transmission Losses, Distribution Losses, and Direct Current Tie (DC Tie) exports.

Adjusted Static Models

Load Profiles that are generated from statistical models that are based on static historical Load data, and adjusted for conditions of the day (e.g., weather, Season, etc.).

Adjustment Period

For each Operating Hour, the time between 1800 in the Day-Ahead up to the start of the hour before that Operating Hour.

Advance Action Notice (AAN)

A type of Operating Condition Notice (OCN) that identifies a possible future Emergency Condition and describes future action ERCOT expects to take to address that condition unless the need for ERCOT action is alleviated by Qualified Scheduling Entity (QSE) and/or Transmission Service Provider (TSP) actions or by other system developments.

Advanced Meter

Any new or appropriately retrofitted meter that functions as part of a system that includes such meters and the associated hardware, software, and communications devices, that collects time-differentiated energy usage, and that is deployed pursuant to P.U.C. SUBST. R. 25.130, Advanced Metering.

Advanced Metering System (AMS)

A system, including Advanced Meters and the associated hardware, software, and communications devices, that collects time-differentiated energy usage and is deployed pursuant to P.U.C. SUBST. R. 25.130, Advanced Metering.

Advisory

The second of three levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

Affiliate

(1) An Entity that directly or indirectly owns or holds at least 5% of the voting securities of a Market Participant; or

(2) An Entity in a chain of successive ownership of at least 5% of the voting securities of a Market Participant; or

(3) An Entity that has at least 5% of its voting securities owned or controlled, directly or indirectly, by a Market Participant; or

(4) An Entity that has at least 5% of its voting securities owned or controlled, directly or indirectly, by an Entity who directly or indirectly owns or controls at least 5% of the voting securities of a Market Participant or an Entity in a chain of successive ownership of at least 5% of the voting securities of a Market Participant; or

(5) A person who is an officer or director of a Market Participant or of a corporation in a chain of successive ownership of at least 5% of the voting securities of a Market Participant.

(6) Notwithstanding any part of this definition, any Entity that would be considered an Affiliate due to its participation in a chain of successive ownership of a Market Participant shall not for that reason be considered an Affiliate if:

(a) It does not own 50% or more of the voting securities of any other Entity in the chain; or

(b) Its participation in the chain is only as a successive owner of an Entity in the chain that does not own 50% or more of the voting securities of another Entity in that chain.

(7) Provided that the Entity holding ownership or control of voting securities in a Market Participant does not hold such ownership or control for the purpose of exercising or influencing control of that Market Participant, then for the purposes of that relationship, the term "Entity," as used in this definition, shall not include:

(a) A broker or dealer registered under the Securities Exchange Act of 1934, 15 U.S.C. § 78;

(b) A bank or insurance company as defined under the Securities Exchange Act of 1934, 15 U.S.C. § 78;

(c) An investment adviser registered under state law or the Investment Advisers Act of 1940, 15 U.S.C. §§ 80b1-80b21;

(d) An investment company registered under the Investment Company Act of 1940, 15 U.S.C. §§ 80a1-80a64; or

(e) An employee benefit plan, pension fund, endowment fund, or other similar entity.

(8) ERCOT may request either of the following as conclusive evidence of the purpose required in paragraph (7) above:

(a) An affidavit attesting to that purpose if such affidavit is signed by the Entity owning the securities; or

(b) A report reflecting that purpose filed by the owning entity with the Securities and Exchange Commission.

(9) Notwithstanding any other provision of this Section 2.1, “Affiliate” includes any Entity determined by the Public Utility Commission of Texas (PUCT) to be an Affiliate.

Aggregate Generation Resource (AGR) (*see* Resource Attribute)

Aggregate Load Resource (ALR) (*see* Resource)

Agreement

A signed written agreement between ERCOT and a Market Participant using one of the standard form agreements in Section 22, Attachments, including those agreements containing changes to the standard form, which changes have been approved by the ERCOT Board.

Alternative Dispute Resolution (ADR)

Procedures, outlined in Section 20, Alternative Dispute Resolution Procedure, for settling disputes by means other than litigation.

Ancillary Service

A service necessary to support the transmission of energy to Loads while maintaining reliable operation of the Transmission Service Provider's (TSP's) transmission system using Good Utility Practice.

[NPRR857: Replace the above definition "Ancillary Service" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Ancillary Service

A service necessary to support the transmission of energy to Loads while maintaining reliable operation of the transmission system using Good Utility Practice.

Ancillary Service Assignment

Ancillary Service Resource Responsibility assigned to an On-Line Resource pursuant to paragraph (4) of Section 6.5.9.3.3, Watch.

[NPRR1013: Delete the above definition "Ancillary Service Assignment" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Capacity Monitor

A set of processes described in Section 8.1.1.3, Ancillary Service Capacity Compliance Criteria, to determine the Real-Time capability of Resources to provide Ancillary Service.

[NPRR1013: Insert the following definition "Ancillary Service Demand Curve (ASDC)" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Demand Curve (ASDC)

A curve that reflects the value of each Ancillary Service product by price/quantity pairs for each hour of the Operating Day.

[NPRR1013: Insert the following definition "Ancillary Service Imbalance" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Imbalance

The difference between the amount of an Ancillary Service cleared in the Day-Ahead Market (DAM) and through trades and the amount of that Ancillary Service awarded in the Real-Time Market (RTM).

Ancillary Service Obligation

For each Ancillary Service, a Qualified Scheduling Entity's (QSE's) ERCOT-allocated share of total ERCOT System needs for that Ancillary Service.

Ancillary Service Offer

An offer to supply Ancillary Service capacity in the Day-Ahead Market (DAM) or a Supplemental Ancillary Service Market (SASM).

[NPRR1013: Replace the definition "Ancillary Service Offer" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Offer

An offer to supply Ancillary Service capacity in the Day-Ahead Market (DAM) or Real-Time Market (RTM).

> ***Resource-Specific Ancillary Service Offer***
>
> A Resource-specific offer to supply Ancillary Service capacity in the Day-Ahead Market (DAM) or Real-Time Market (RTM).

Ancillary Service Only Offer

An offer to sell Ancillary Service capacity in the Day-Ahead Market (DAM) that is not associated with a specific Resource.

Ancillary Service Plan

A plan produced by ERCOT, as described in Section 4.2.1, Ancillary Service Plan and Ancillary Service Obligation, which identifies the types and amount of Ancillary Service necessary for each hour of the Operating Day.

[NPRR1013: Insert the following definition "Ancillary Service Position" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Ancillary Service Position

The net amount of Ancillary Service capacity to which a Qualified Scheduling Entity (QSE) has financially committed in the ERCOT market, as described in Section 5.4.1, Ancillary Service Positions.

Ancillary Service Resource Responsibility

The MW of an Ancillary Service that each Resource is obligated to provide in Real-Time rounded to the nearest MW.

[NPRR1013: Delete the above definition "Ancillary Service Resource Responsibility" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Schedule

The MW of each Ancillary Service that each Resource is providing in Real-Time and the MW of each Ancillary Service for each Resource for each hour in the Current Operating Plan (COP).

[NPRR1013: Delete the above definition "Ancillary Service Schedule" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Supply Responsibility

The net amount of Ancillary Service capacity that a Qualified Scheduling Entity (QSE) is obligated to deliver to ERCOT, by hour and service type, from Resources represented by the QSE.

[NPRR1013: Delete the above definition "Ancillary Service Supply Responsibility" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Ancillary Service Trade

A QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

Applicable Legal Authority (ALA)

A Texas or federal law, rule, regulation, or applicable ruling of the PUCT or any other regulatory authority having jurisdiction, an order of a court of competent jurisdiction, or a rule, regulation, applicable ruling, procedure, protocol, guide or guideline of the Independent Organization, or any Entity authorized by the Independent Organization to perform registration or settlement functions.

Area Control Error (ACE)

A calculation of the MW correction needed to control the actual system frequency to the scheduled system frequency.

Authorized Representative

The person(s) designated by an Entity during the registration process in Section 16, Registration and Qualification of Market Participants, who is responsible for authorizing all registration information required by ERCOT Protocols and ERCOT business processes, including any changes in the future, and will be the contact person(s) between the registered Entity and ERCOT for all business matters requiring authorization by ERCOT.

Automatic Voltage Regulator (AVR)

A device on a Generation Resource or a control system at the Facility of a Generation Resource used to automatically control the voltage to an established Voltage Set Point.

[NPRR989: Replace the above definition "Automatic Voltage Regulator (AVR)" with the following upon system implementation:]

Automatic Voltage Regulator (AVR)

A device on a Generation Resource or a control system at the Facility of a Generation Resource or Energy Storage Resource (ESR) used to automatically control the voltage to an established Voltage Set Point.

Availability Plan

An hourly representation of availability of Reliability Must-Run (RMR) Units or an hourly representation of the capability of Black Start Resources as submitted to ERCOT by 0600 in the Day-Ahead by Qualified Scheduling Entities (QSEs) representing RMR Units or Black Start Resources. An hourly representation of availability of Firm Fuel Supply Service Resources (FFSSRs) as submitted to ERCOT 14 days prior to the Operating Day by QSEs representing FFSSRs.

[NPRR885: Replace the above definition "Availability Plan" with the following upon system implementation:]

Availability Plan

An hourly representation of availability of Reliability Must-Run (RMR) Units, Must-Run Alternatives (MRAs), or an hourly representation of the capability of Black Start Resources as submitted to ERCOT by 0600 in the Day-Ahead by Qualified Scheduling Entities (QSEs) representing RMR Units, MRAs, or Black Start Resources. An hourly representation of availability of Firm Fuel Supply Service Resources (FFSSRs) as submitted to ERCOT 14 days prior to the Operating Day by QSEs representing FFSSRs.

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Bank Business Day (*see* Business Day)

Bankrupt

The condition of an Entity that:

(a) Files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;

(b) Makes an assignment or any general arrangement for the benefit of creditors;

(c) Has a liquidator, administrator, receiver, trustee, conservator, or similar official appointed with respect to it or any substantial portion of its property or assets; or

(d) Is generally unable to pay its debts as they fall due.

Base Point

The MW output level for a Resource produced by the Security-Constrained Economic Dispatch (SCED) process.

Black Start Resource (*see* Resource Attribute)

Black Start Service (BSS)

An Ancillary Service provided by a Resource able to start without support of the ERCOT Transmission Grid.

Black Start Service (BSS) Back-up Fuel

Fuel that is stored on site at the location of a Black Start Resource and that is available at all times and contracted with ERCOT for the purpose of powering the Resource when following ERCOT or the local Transmission Operator (TO) instruction to start without support of the ERCOT Transmission Grid in response to a Blackout or Partial Blackout.

Blackout

A condition in which frequency for the entire ERCOT System has dropped to zero and Generation Resources are no longer serving Load.

Partial Blackout

A condition in which an uncontrolled separation of a portion of the ERCOT System occurs and frequency for that portion has dropped to zero and Generation Resources within that portion are no longer serving Load and restoration is dependent on either internal Black Start Plans or assistance for restoration is needed from neighboring Transmission Operator(s) (TO(s)) within the ERCOT System which requires ERCOT coordination.

Block Load Transfer (BLT)

A transfer system that isolates a group of Loads from the Control Area in which they normally are served and then connects them to another Control Area. Such transfer systems involve either transferring Loads normally in the ERCOT Control Area to a non-ERCOT Control Area or transferring Loads normally in non-ERCOT Control Areas to the ERCOT Control Area.

Bus Load Forecast

A set of processes used by ERCOT to determine a forecast of the Load at each Electrical Bus in the ERCOT Transmission Grid.

Business Day

Monday through Friday, excluding observed holidays listed below:

(a) New Year's Day;

(b) Martin Luther King, Jr. Day;

(c) Memorial Day;

(d) Independence Day;

(e) Labor Day;

(f) Thanksgiving Thursday and Friday; and

(g) Two days at Christmas, as designated from time to time by the ERCOT CEO.

Bank Business Day

Any day during which the United States Federal Reserve Bank of New York is open for normal business activity.

Retail Business Day

Same as a Business Day, except in the case of retail transactions processed by a TSP or Distribution Service Provider (DSP), Competitive Retailers (CRs) shall substitute the TSP or DSP holidays for ERCOT holidays when determining the time available to the TSP or DSP to process the transaction. For additional important information related to Retail Business Days, please refer to the Retail Market Guide.

Business Hours

0800 to 1700 Central Prevailing Time (CPT) on Business Days.

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Capacity Trade

A QSE-to-QSE financial transaction that transfers responsibility to supply capacity between a buyer and a seller at a Settlement Point.

Cash Collateral

A Counter-Party's cash funds held by ERCOT to satisfy ERCOT creditworthiness requirements, as described in paragraph (d) of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

Central Prevailing Time (CPT)

Either Central Standard Time or Central Daylight Time, in effect in Austin, Texas.

Comision Federal de Electricidad (CFE)

The government agency in Mexico charged with the responsibility of operating the Mexican national electricity grid.

Commercial Operations Date

The date on which an Interconnecting Entity (IE) or a Resource Entity expects that construction and trial operation of a Resource will be completed and the Resource is expected to complete the Resource interconnection process and be approved for participation in ERCOT market operations.

Common Information Model (CIM)

A standard way to communicate information about a transmission system. The CIM is used to describe the ERCOT transmission system topology consisting of Transmission Elements, including all the parameters needed to describe the Transmission Elements and how they interrelate to one another. The CIM that ERCOT and the TSP use must conform to the North American Electric Reliability Corporation (NERC) and Electric Power Research Institute (EPRI) standards for CIMs.

[NPRR857: Replace the above definition "Common Information Model (CIM)" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Common Information Model (CIM)

A standard way to communicate information about a transmission system. The CIM is used to describe the ERCOT transmission system topology consisting of Transmission Elements, including all the parameters needed to describe the Transmission Elements and how they interrelate to one another. The CIM that ERCOT and Market Participants use must conform to the North American Electric Reliability Corporation (NERC) and Electric Power Research Institute (EPRI) standards for CIMs.

Competitive Constraint

A contingency and limiting Transmission Element pair or group of Transmission Elements associated with a Generic Transmission Constraint (GTC) that is determined to be competitive using the process defined in Section 3.19, Constraint Competitiveness Tests.

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).

Competitive Retailer (CR) of Record

The CR assigned to the Electric Service Identifier (ESI ID) in ERCOT's database. There can be no more than one CR of Record assigned to an ESI ID for any given time period.

Compliance Period

A calendar year beginning January 1 and ending December 31 in which Renewable Energy Credits (RECs) are required of a Retail Entity.

Compliance Premium

A payment awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy source that is not powered by wind and meets the criteria of subsection (l) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. For the purpose of the Renewable Portfolio Standard (RPS) requirements, one Compliance Premium is equal to one REC.

Conductor/Transformer 2-Hour Rating (*see* Rating)

Congestion Revenue Right (CRR)

A financial instrument that entitles the holder to be charged or to receive compensation (*i.e.*, congestion rent), depending on the instrument, when the ERCOT Transmission Grid is congested in the DAM or in Real-Time.

Flowgate Right (FGR)

A type of CRR that entitles the holder to receive compensation and is evaluated in each CRR Auction and DAM as the positive power flows represented by the quantity of the CRR bid or offer (MW) on a flowgate (i.e., predefined directional network element or a predefined bundle of directional network elements).

Point-to-Point (PTP) Obligation

A type of CRR that entitles the holder to be charged or to receive compensation and is evaluated in each CRR Auction and DAM as the positive and negative power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points of the quantity represented by the CRR bid or offer (MW).

Point-to-Point (PTP) Obligation with Links to an Option

A type of CRR that entitles a Non-Opt-In Entity’s (NOIE’s) PTP Obligation bought in the DAM to be reflective of the NOIE’s PTP Option. To qualify as a PTP Obligation of this type, the source and sink pairs on both the NOIE’s PTP Obligation and the NOIE’s PTP Option shall be the same, and the MWs of the NOIE’s PTP Obligations shall be less than or equal to the number of MWs of the NOIE’s PTP Option. Qualified PTP Obligations with Links to an Option shall be settled as if they were a PTP Option.

Point-to-Point (PTP) Option

A type of CRR that is evaluated in each CRR Auction and DAM as the positive power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points in the quantity represented by the CRR bid or offer (MW), excluding all negative flows on all directional network elements. A PTP Option entitles the holder to receive compensation equal to the positive energy price difference between the sink and the source Settlement Point Prices. A PTP Option with Refund is evaluated in the same manner and compensated as described in Section 7.4.2, PCRR Allocations and Nominations.

Congestion Revenue Right (CRR) Account Holder

An Entity that is qualified to become the owner of record of CRRs and is registered as a CRR Account Holder with ERCOT.

> ***Participating Congestion Revenue Right (CRR) Account Holder***
>
> For a given CRR Auction, a CRR Account Holder who either owns one or more CRRs effective during the Operating Days covered by the CRR Auction, or whose Counter-Party has a non-zero credit limit available and allocated to the CRR Auction as described in paragraph (1) of Section 7.5.5.3, Auction Process.

Congestion Revenue Right (CRR) Auction

A periodic auction by ERCOT that allows eligible CRR Account Holders to buy and sell CRRs.

Congestion Revenue Right (CRR) Auction Capacity

The fraction of the network capacity that is offered for sale in a given CRR Auction.

Congestion Revenue Right (CRR) First Offering

The CRR Auction, which is part of a CRR Long-Term Auction Sequence, in which a series of calendar months of CRRs is offered for sale for the first time.

Congestion Revenue Right (CRR) Long-Term Auction Sequence

A series of six CRR Auctions held consecutively, each of which entails the sale of a six-month window of CRRs.

Congestion Revenue Right (CRR) Monthly Auction

The CRR Auction in which a calendar month is offered for sale for the last time. This CRR Auction may, but is not required to, be conducted on the same dates as a CRR Auction that is part of a CRR Long-Term Auction Sequence.

Congestion Revenue Right (CRR) Network Model

A model of ERCOT network topology to be used in conducting a CRR Auction. It must be based on, but is not the same as, the Updated Network Model, as detailed in Section 3.10.3, CRR Network Model.

Congestion Revenue Right (CRR) Owner

A CRR Account Holder that owns one or more CRRs.

Constant Frequency Control (CFC)

An operating mode of an Automatic Generation Control (AGC) system. While in CFC, an AGC system will monitor only the frequency error to determine Resource adjustments needed to balance sources and obligations. CFC controls generation to increase or decrease by the amount of frequency deviation multiplied by the bias.

Constraint Management Plan (CMP)

A set of pre-defined manual transmission system actions, or automatic transmission system actions that do not constitute a Remedial Action Scheme (RAS), which are executed in response to system conditions to prevent or to resolve one or more thermal or non-thermal transmission security violations or to optimize the transmission system. CMPs may be developed in cases where studies indicate economic dispatch alone may be unable to resolve a transmission security violation or in response to Real-Time conditions where Security-Constrained Economic Dispatch (SCED) is unable to resolve a transmission security violation. ERCOT will employ CMPs to facilitate the market use of the ERCOT Transmission Grid, while maintaining system security and reliability in accordance with the Protocols, Operating Guides and North American Electric Reliability Corporation (NERC) Reliability Standards. CMPs are intended to supplement, not to replace, the use of SCED for prevention or resolution of one or more thermal or non-thermal transmission security violations. CMPs include, but are not limited to the following:

Automatic Mitigation Plan (AMP)

A set of pre-defined automatic actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating, excluding any set of automatic actions that constitute a Remedial Action Scheme. AMPs shall only include schemes which switch series reactors by monitoring quantities that are solely located at the same substation as the switched device. AMPs shall not include adjusting or tripping generation or Load shedding and shall not be implemented on Interconnection Reliability Operating Limits (IROLs).

Mitigation Plan

A set of pre-defined manual actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A Mitigation Plan must be implementable and may include transmission switching and Load shedding. Mitigation Plans shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

Pre-Contingency Action Plan (PCAP)

A set of pre-defined manual actions to execute pre-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A PCAP may include transmission switching and does not include Load shedding. A PCAP may also be implemented for the duration of an Outage and shall be included in the Outage Scheduler as soon as practicable.

Remedial Action Plan (RAP)

A set of pre-defined manual actions to execute post-contingency to address voltage issues or in order to reduce loading on one or more given, monitored Transmission Facilities to below their Emergency Rating within 15 minutes. RAPs are sufficiently dependable to assume they can be executed without loss of reliability to the interconnected network, with restoration of normal operating conditions and below Normal Rating within two hours as defined in the Network Operations Model. RAPs may be relied upon in allowing additional use of the transmission system in Security-Constrained Economic Dispatch (SCED). RAPs shall not include generation re-Dispatch or Load shedding.

Temporary Outage Action Plan (TOAP)

A temporary set of pre-defined manual actions to execute post-contingency, during a specified Transmission Facility or Resource Outage, in order to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A TOAP must be implementable and may include transmission switching and/or Load shedding. TOAPs shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

Continuous Service Agreement (CSA)

An arrangement between the owner or controller of a leased Premise and a CR wherein the CR provides service to the leased Premise between tenants so that the Premise does not experience discontinuation of electric service during vacancy.

Control Area

An electrical system, bound by interconnect (tie line) metering and telemetry, that continuously regulates, through automatic Resource control, its Resource(s) and interchange schedules to match its system Load and frequency schedule.

Control Area Operator (CAO)

An individual or set of individuals responsible for monitoring and controlling operation of a Control Area.

Controllable Load Resource (*see* Resource)

Controllable Load Resource Desired Load

The MW consumption for a Controllable Load Resource produced by summing its Scheduled Power Consumption and Ancillary Service deployments.

[NPRR1013: Delete the above definition "Controllable Load Resource Desired Load" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Cost Allocation Zone

One of the four zones in effect during the 2003 ERCOT market as they are changed pursuant to Section 3.4.2, Load Zone Modifications. A Cost Allocation Zone may be used by ERCOT to uplift certain costs to a QSE's Load regardless of NOIE Load Zone.

Counter-Party

A single Entity that is a QSE and/or a CRR Account Holder. A Counter-Party includes all registrations as a QSE, all subordinate QSEs, and all CRR Account Holders by the same Entity.

Credible Single Contingency

(1) The Forced Outage of any single Transmission Facility or, during a single fault, the Forced Outage of multiple Transmission Facilities (single fault multiple element);

(2) The Forced Outage of a double-circuit transmission line in excess of 0.5 miles in length;

(3) The Forced Outage of any single Generation Resource, and in the case of a Combined Cycle Train, the Forced Outage of the combustion turbine and the steam turbine if they cannot operate separately as provided in the Resource registration process; or

(4) For transmission planning purposes, contingencies are defined in the Planning Guide.

Critical Load

A Load that is designated as, or has a pending application to be designated as, a Critical Load Public Safety Customer, Critical Load Industrial Customer, Chronic Condition Residential

Customer, or Critical Care Residential Customer pursuant to P.U.C. SUBST. R. 25.497, Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers, or as a critical load under any other category identified under Public Utility Commission of Texas (PUCT) Rules.

Current Operating Plan (COP)

A plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service Schedule.

[NPRR1013: Replace the definition "Current Operating Plan (COP)" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Current Operating Plan (COP)

A plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service capabilities.

Current Operating Plan (COP) and Trades Snapshot

A record of a QSE's Capacity Trades, Energy Trades, and most recent COP.

[NPRR1013: Delete the above definition "Current Operating Plan (COP) and Trades Snapshot" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Customer

An Entity that purchases electricity for its consumption.

Customer Choice

The freedom of a retail Customer to purchase electric services, either individually or on an aggregated basis with other retail Customers, from the provider or providers of the Customer's choice and to choose among various fuel types, energy efficiency programs, and renewable power suppliers.

Customer Registration Database

The database maintained by the registration agent containing information identifying each Premise, including current and previous CRs serving the Premise.

Cybersecurity Contact

The person, desk, or hotline designated by an Entity, as set forth in Section 16, Registration and Qualification of Market Participants, that is the primary point of contact for communications between the registered Entity and ERCOT with respect to Cybersecurity Incidents. A Market Participant may designate a temporary Cybersecurity Contact for a particular Cybersecurity Incident pursuant to Section 16.19, Cybersecurity Incident Notification.

Cybersecurity Incident

A malicious or suspicious act that compromises or disrupts a computer network or system that could foreseeably jeopardize the reliability or integrity of the ERCOT System or ERCOT's ability to perform the functions of an independent organization under the Public Utility Regulatory Act (PURA).

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Data Agent-Only Qualified Scheduling Entity (QSE) (*see* Qualified Scheduling Entity (QSE))

Data Aggregation

The process of netting, grouping, and summing Load consumption data, applying appropriate profiles, Transmission Loss Factors (TLFs), and Distribution Loss Factors (DLFs) and calculating and allocating UFE to determine each QSE and/or Load Serving Entity's (LSE's) responsibility by Settlement Interval by Load Zone and by other prescribed aggregation determinants.

Data Aggregation System (DAS)

The database and communication system that collects meter data from TSPs, DSPs and ERCOT Polled Settlement (EPS) Meters. The system performs aggregation functions to Load data in order to satisfy certain objectives, such as providing TSPs with Load share data to use in billing CRs, assigning QSE Load responsibility, and assisting CRs and QSEs in their Settlement responsibilities. The data is also compiled along Load and Weather Zones.

Data Archive

An integrated normalized data structure of all the target source systems' transactions. The population of the Data Archive is an extraction of data from the transaction systems without altering the data. The Data Archive is used to populate the Data Warehouse.

Data Warehouse

De-normalized data stored in a schema, physically optimized to handle high volumes of data and concurrent user access, and generally lightly indexed.

Day-Ahead

The 24-hour period before the start of the Operating Day.

Day-Ahead Market (DAM)

A daily, co-optimized market in the Day-Ahead for Ancillary Service capacity, certain CRRs, and forward financial energy transactions.

Day-Ahead Market (DAM)-Committed Interval

A Settlement Interval for which the Resource has been committed due to a DAM award.

Day-Ahead Market (DAM) Energy Bid

A proposal to buy energy in the DAM at a Settlement Point at a monotonically decreasing price with increasing quantity.

Day-Ahead Market (DAM) Energy-Only Offer

A QSE's willingness to sell energy at or above a certain price and at a certain quantity at a specific Settlement Point in the DAM. A DAM Energy-Only Offer Curve may be offered only in the DAM. DAM Energy-Only Offer Curves are not Resource-specific.

Day-Ahead Market (DAM) Resettlement Statement (*see* Settlement Statement)

Day-Ahead Market (DAM) Statement (*see* Settlement Statement)

Day-Ahead Operations

The Day-Ahead process consisting of the DAM and Day-Ahead Reliability Unit Commitment (DRUC).

Day-Ahead Reliability Unit Commitment (DRUC)

A Reliability Unit Commitment (RUC) process performed for the next Operating Day.

[NPRR1013: Insert the following definition "Day-Ahead System-Wide Offer Cap (DASWCAP)" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Day-Ahead System-Wide Offer Cap (DASWCAP)

The DASWCAP shall be determined in accordance with Public Utility Commission of Texas (PUCT) Substantive Rules.

Delivery Plan

A plan by ERCOT containing the hours and levels of operation that a Reliability Must-Run (RMR) Unit is instructed to operate.

Demand

The amount of instantaneous electric power in MW delivered at any specified point or points on a system.

Designated Representative

A responsible natural person authorized by an Entity to register with ERCOT as a Renewable Energy Credit (REC) Account Holder or manage an REC Account.

Digital Certificate

An electronic file installed on a programmatic interface or an individual's assigned computer used to authenticate that the interface or individual is authorized for secure electronic messaging with ERCOT's computer systems.

Direct Current Tie (DC Tie)

Any non-synchronous transmission interconnections between ERCOT and non-ERCOT electric power systems.

Direct Current Tie (DC Tie) Curtailment Notice

A notification issued by ERCOT indicating the need for curtailment of DC Tie import or export schedules due to current system conditions.

Direct Current Tie (DC Tie) Load

A Load used to represent the withdrawal of power from the ERCOT System to a DC Tie.

[NPRR857: Insert the following definition "Direct Current Tie Operator (DCTO)" upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Direct Current Tie Operator (DCTO)

An Entity that operates a Direct Current Tie (DC Tie) interconnected to the ERCOT System and that is registered as a DCTO.

Direct Current Tie (DC Tie) Resource

A Resource used to represent the injection of power into the ERCOT System from a DC Tie.

Direct Current Tie (DC Tie) Schedule

An energy schedule between ERCOT and a non-ERCOT Control Area and is represented by a corresponding Electronic Tag (e-Tag) that contains the physical transaction information such as the Settlement Point energy amount (MW), the associated DC Tie, and the buyer and seller.

Direct Load Control (DLC)

The control of end-use equipment (e.g., air conditioning equipment, water heaters) to reduce or increase energy consumption during select periods.

Dispatch

The act of issuing Dispatch Instructions.

Dispatch Instruction

A specific command issued by ERCOT to a Qualified Scheduling Entity (QSE), Transmission Service Provider (TSP), or Distribution Service Provider (DSP) in the operation of the ERCOT System.

[NPRR857: Replace the above definition "Dispatch Instruction" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Dispatch Instruction

A specific command issued by ERCOT to a Qualified Scheduling Entity (QSE), Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), or Distribution Service Provider (DSP) in the operation of the ERCOT System.

Dispute Contact

The individual associated with a Market Participant who is the primary contact with ERCOT regarding the pursuit of an Alternative Dispute Resolution (ADR) request.

Distributed Generation (DG)

An electrical generating facility located at a Customer's point of delivery (point of common coupling) ten megawatts (MW) or less and connected at a voltage less than or equal to 60 kilovolts (kV) which may be connected in parallel operation to the utility system.

Distributed Renewable Generation (DRG)

Electric generation with a capacity of not more than 2,000 kW provided by a renewable energy technology that is installed on a retail electric Customer's side of the meter.

Distribution Generation Resource (*see* Resource)

Distribution Loss Factor (DLF)

The ratio of a DSP’s estimated Distribution Losses to the total amount of energy deemed consumed (Interval Data Recorder (IDR) plus profiled consumption) on the DSP’s system.

Distribution Losses

The difference between the energy delivered to the Distribution System and the energy consumed by Customers connected to the Distribution System.

Distribution Service Provider (DSP)

An Entity that owns or operates a Distribution System for the delivery of energy from the ERCOT Transmission Grid to Customers.

Distribution System

That portion of an electric delivery system operating under 60 kV that provides electric service to Customers or Wholesale Customers.

DUNS Number

A unique nine-digit common company identifier used in electronic commerce transactions, supplied by the Data Universal Numbering System (DUNS).

Dynamic Rating

The current-carrying capability of a Transmission Element adjusted to take into account the effect of ambient weather conditions.

Dynamic Rating Processor

A process used to establish ERCOT Transmission Element limits based upon factors such as ambient temperature and wind speed.

Dynamically Scheduled Resource (DSR) (*see* Resource Attribute)

Dynamically Scheduled Resource (DSR) Load

A Load that a QSE designates to be followed by a Dynamically Scheduled Resource (DSR).

[NPRR1000: Delete the definition "Dynamically Scheduled Resource (DSR) Load" above upon system implementation.]

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Electric Cooperative (EC)

(a) A corporation organized under the Electric Cooperative Corporation Act, TEX. UTIL. CODE ANN. ch 161 (Vernon 1998 & Supp. 2007);

(b) A corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct business in Texas; or

(c) A successor to an electric cooperative created before June 1, 1999 under a conversion plan approved by a vote of the members of the electric cooperative, regardless of whether the successor later purchases, acquires, merges with, or consolidates with other electric cooperatives.

Electric Reliability Council of Texas, Inc. (ERCOT)

A Texas nonprofit corporation that has been certified by the PUCT as the Independent Organization for the ERCOT Region.

Electric Reliability Organization

The organization approved by the Federal Energy Regulatory Commission (FERC) to perform the electric reliability organization functions described in the Electricity Modernization Act of 2005, 16 U.S.C. § 824o (2005).

Electric Service Identifier (ESI ID)

The basic identifier assigned to each Service Delivery Point used in the registration and settlement systems managed by ERCOT or another Independent Organization.

Electrical Bus

(1) A physical transmission element defined in the Network Operations Model that connects, using breakers and switches, one or more:

  (a) Loads;

(b) Lines;

(c) Transformers;

(d) Generators;

(e) Capacitors;

(f) Reactors;

(g) Phase shifters; or

(h) Other reactive control devices to the ERCOT Transmission Grid where there is negligible impedance between the connected Transmission Elements.

(2) All Electrical Buses are designated by ERCOT and Transmission Service Providers (TSPs) for modeling the electrical topology of the ERCOT Transmission Grid.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) All Electrical Buses are designated by ERCOT and Market Participants for modeling the electrical topology of the ERCOT Transmission Grid.

Resource Connectivity Node

The Electrical Bus to which the terminal of a Resource is connected.

Electrically Similar Settlement Points

Two or more distinct Settlement Points that are either mapped to the same electrical location in a market model or are mapped to locations that are connected by a transmission element with a reactance of less than 0.0005 per unit.

Eligible Transmission Service Customer

A Transmission and/or Distribution Service Provider (TDSP) (for all uses of its transmission system), or any electric utility, MOU, EC, power generation company, CR, REP, federal power marketing agency, exempt wholesale generator, Qualifying Facility (QF), Independent Power

Marketer, or other Entity that the PUCT has determined to be an Eligible Transmission Service Customer.

Emergency Base Point

The target MW output level for a Resource that is selected by ERCOT during an Emergency Condition or Watch.

Emergency Condition

An operating condition in which the safety or reliability of the ERCOT System is compromised or threatened, as determined by ERCOT.

Emergency Notice

The communication issued by ERCOT to declare that ERCOT is operating in an Emergency Condition.

Emergency Ramp Rate

The maximum rate of change (up and down) in MW per minute of a Resource to provide Responsive Reserve (RRS) that is deployed by ERCOT and that is provided to ERCOT in up to ten segments, each represented by a single MW per minute value (across the capacity of the Resource), which describes the available rate of change for the given range (between High Sustained Limit (HSL) and Low Sustained Limit (LSL)) of the generation or consumption of a Resource. In Real-Time Security-Constrained Economic Dispatch (SCED) Dispatch, the up and down Emergency Ramp Rates are telemetered by the Qualified Scheduling Entity (QSE) to ERCOT and represent the total capacity (in MW) that the Resource can change from its current actual generation or consumption within the next five minutes divided by five.

[NPRR863 and NPRR1013: Replace the above definition “Emergency Ramp Rate” with the following upon system implementation of NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project, respectively:]

Emergency Ramp Rate

The maximum rate of change (up and down) in MW per minute of a Resource to provide energy during Emergency Conditions that is provided to ERCOT in up to ten segments, each represented by a single MW per minute value (across the capacity of the Resource), which describes the available rate of change for the given range (between High Sustained Limit (HSL) and Low Sustained Limit (LSL)) of the generation or consumption of a Resource. In Real-Time Security-Constrained Economic Dispatch (SCED) Dispatch, the up and down Emergency Ramp Rates are telemetered by the Qualified Scheduling Entity (QSE) to ERCOT and represent the total capacity (in MW) that the Resource can change from its current actual generation or consumption within the next five minutes divided by five.

Emergency Rating (*see* Rating)

Emergency Response Service (ERS)

An emergency service consistent with P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), to be deployed by ERCOT to help prevent or alleviate an actual or anticipated Energy Emergency Alert (EEA) event. ERS is not an Ancillary Service.

ERS-10

ERS with a ten-minute ramp period.

ERS-30

ERS with a 30-minute ramp period.

Non-Weather-Sensitive ERS

A type of ERS in which an ERS Resource may participate in ERS without meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1, Emergency Response Service Procurement.

Weather-Sensitive ERS

A type of ERS in which an ERS Load may participate in ERS only after meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1.

Emergency Response Service (ERS) Contract Period

A period designated by ERCOT during which an ERS Resource is obligated to provide ERS consisting of all or part of the contiguous hours in an ERS Standard Contract Term.

Emergency Response Service (ERS) Generator

Either (1) an individual generator contracted to provide ERS which is not a Generation Resource or a source of intermittent renewable generation and which provides ERS by injecting energy to the ERCOT System, or (2) an aggregation of such generators.

Emergency Response Service (ERS) Load

A Load or aggregation of Loads contracted to provide ERS.

Emergency Response Service (ERS) Resource

Either an ERS Load or an ERS Generator.

Emergency Response Service (ERS) Self-Provision

The designation by a QSE of one or more ERS Resources to meet some or all of that QSE's Load Ratio Share (LRS) of the total ERCOT-wide cost of ERS.

Emergency Response Service (ERS) Standard Contract Term

One of four periods for which ERCOT may procure ERS.

Emergency Response Service (ERS) Time Period

Blocks of hours in an ERS Standard Contract Term in which ERS Resources are contractually committed to provide ERS.

[NPRR1014: Insert the following definition "Energy Bid/Offer Curve" upon system implementation:]

Energy Bid/Offer Curve

A proposal from an Energy Storage Resource (ESR) to buy and sell energy at a Settlement Point in the form of a single monotonically non-decreasing price curve that covers both the charging and discharging MW range and provides a bid price for charging and an offer price for discharging.

Energy Emergency Alert (EEA)

An orderly, predetermined procedure for maximizing use of available Resources and, only if necessary, curtailing load during an Emergency Condition while providing for the maximum possible continuity of service and maintaining the integrity of the ERCOT System.

Energy Imbalance Service

An Ancillary Service that is provided when a difference occurs between the scheduled and the actual delivery of energy in Real-Time.

[NPRR1013: Replace the definition "Energy Imbalance Service" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Energy Imbalance Service

The difference between the amount of energy cleared in the Day-Ahead Market (DAM) and through trades and the amount of delivery of that energy in the Real-Time Market (RTM).

Energy Offer Curve

A proposal to sell energy at a Settlement Point at a monotonically increasing price with increasing quantity.

Energy Storage Resource (ESR) (*see* Resource)

Energy Storage System (ESS)

A facility, process, or device(s) that receives electric energy and stores it, in any form, for the purpose of later releasing electrical energy.

Energy Trade

A QSE-to-QSE financial transaction that transfers responsibility for energy between a buyer and a seller at a Settlement Point.

Entity

Any natural person, partnership, municipal corporation, cooperative corporation, association, governmental subdivision, or public or private organization.

[NPRR863 and NPRR1096: Insert applicable portions of the following definition "ERCOT Contingency Reserve Service (ECRS)" upon system implementation:]

ERCOT Contingency Reserve Service (ECRS)

An Ancillary Service that provides operating reserves that is intended to:

(a) Restore Responsive Reserve (RRS) within ten minutes of a frequency deviation that results in significant depletion of RRS by restoring frequency to its scheduled value to return the system to normal;

(b) Provide energy or continued Load interruption to avoid or during the implementation of an Energy Emergency Alert (EEA);

(c) Provide backup regulation; and

(d) Be sustained at a specified level for two consecutive hours.

ERCOT Critical Energy Infrastructure Information (ECEII)

Specific engineering, vulnerability, or detailed design information concerning proposed or existing ERCOT System Infrastructure that:

(a) Relates details about the production, generation, transportation, transmission or distribution of energy;

(b) Could foreseeably be useful to a person planning an attack on ERCOT System Infrastructure;

(c) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. § 552, and has not been disclosed to the public through lawful means; and

(d) Does not simply give the general location of the ERCOT System Infrastructure.

ERCOT-Polled Settlement (EPS) Meter

Any meter polled directly by ERCOT for use in the Settlement of the market.

ERCOT Region

The power region, as defined in P.U.C. SUBST. R. 25.5, Definitions, represented by the ERCOT Control Area.

ERCOT System

The interconnected power system that is under the jurisdiction of the PUCT and that is not synchronously interconnected with either the Eastern Interconnection or the Western Electricity Coordinating Council.

ERCOT System Demand

The sum of all power flows, in MW, on the DC Ties and from Generation Resources metered at the points of their interconnections with the ERCOT System at any given time.

ERCOT System Infrastructure

The transmission, distribution, and generation assets that comprise the ERCOT System and the physical and virtual cyber assets used to control the ERCOT System.

ERCOT Transmission Grid

All Transmission Facilities that are part of the ERCOT System.

Exceptional Fuel Cost

The hourly volume-weighted price of natural gas, purchased during an Operating Day or after the Day-Ahead nomination deadline of 1300 Central Prevailing Time (CPT) on the prior Operating Day, submitted in accordance with paragraph (1)(f) of Section 4.4.9.4.1, Mitigated Offer Cap.

External Load Serving Entity (ELSE)

An Entity that is registered as an LSE and is either:

(a) A distribution service provider (as that term is defined in P.U.C. Subst. R. 25.5, Definitions), which includes an electric utility, a Municipally Owned Utility (MOU), or an Electric Cooperative (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; or

(b) The CFE.

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Facilities

Equipment situated for the purpose of conducting service and/or business through use of the ERCOT System

Facility Identification Number

A number assigned to a renewable Resource facility by ERCOT.

Fast Frequency Response (FFR)

The automatic self-deployment and provision by a Resource of their obligated response within 15 cycles after frequency meets or drops below a preset threshold, or a deployment in response to an ERCOT Verbal Dispatch Instruction (VDI) within 10 minutes. Resources capable of automatically self-deploying and providing their full Ancillary Service Resource Responsibility within 15 cycles after frequency meets or drops below a preset threshold and sustaining that full response for at least 15 minutes may provide Responsive Reserve (RRS).

[NPRR1013: Replace the definition "Fast Frequency Response (FFR)" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Fast Frequency Response (FFR)

The automatic self-deployment and provision by a Resource of their obligated response within 15 cycles after frequency meets or drops below a preset threshold, or a deployment in response to an ERCOT Verbal Dispatch Instruction (VDI) within 10 minutes. Resources capable of automatically self-deploying and providing their full Ancillary Service Resource award within 15 cycles after frequency meets or drops below a preset threshold and sustaining that full response for at least 15 minutes may provide Responsive Reserve (RRS).

Fast Responding Regulation Service (FRRS) (*see* Regulation Service)

Fast Responding Regulation Down Service (FRRS-Down) (*see* Regulation Service)

Fast Responding Regulation Up Service (FRRS-Up) (*see* Regulation Service)

15-Minute Rating (*see* Rating)

Financing Person

The lender, security holder, investor, partner, multilateral institution, or other Entity providing financing or refinancing for the business of another Entity, including development, construction, ownership, operation and/or maintenance of a facility or any portion thereof, or any trustee or agent acting on behalf of any of the foregoing.

Firm Fuel Supply Service (FFSS)

A service provided by certain Generation Resources in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption.

Firm Fuel Supply Service Resource (FFSSR)

A Generation Resource that has an obligation to provide Firm Fuel Supply Service (FFSS).

Flowgate Right (FGR) (*see* Congestion Revenue Right (CRR))

Force Majeure Event

Any event beyond the reasonable control of, and that occurs without the fault or negligence of, an Entity whose performance is prevented by the occurrence of such event. Examples of such a Force Majeure Event may include the following, subject to the limitations of the above sentence: an act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or a curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities.

Forced Derate

The unavailability of a portion of a Resource's capacity based on its Seasonal net max sustainable rating provided through the Resource Registration process. For Qualified Scheduling Entities (QSEs) representing Intermittent Renewable Resources (IRRs), the loss of a portion of the capacity shall be due to the unavailability of a portion of the equipment and shall not include capacity changes due to changes in the power source (e.g., wind speed at the Wind-powered Generation Resource (WGR) facility for a WGR, or changes in solar irradiance at the PhotoVoltaic Generation Resource (PVGR) facility for a PVGR).

Forced Outage (*see* Outage)

Frequency Measurable Event (FME)

An event that results in a frequency deviation, identified at ERCOT's sole discretion, and meeting one of the following conditions:

(a) A frequency deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by ERCOT to capture 30 to 40 events per year); or

(b) A cumulative change in generating unit/generating facility, Direct Current Tie (DC Tie), and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by ERCOT to capture 30 to 40 events per year).

[NPRR1013: Insert the following definition "Frequency Responsive Capacity (FRC)" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Frequency Responsive Capacity (FRC)

The telemetered portion of a Generation Resource's total output that represents the fraction of the output provided from capacity that is capable of providing Primary Frequency Response. Capacity not capable of providing Primary Frequency Response includes, but may not be limited to, capacity from duct firing, auxiliary boilers, and other methods that do not immediately respond, arrest, or stabilize frequency excursions following a disturbance without secondary frequency response or instructions from ERCOT.

Fuel Index Price (FIP)

The daily midpoint or average of the prices for natural gas fuel for the Katy area (Katy Hub), expressed in dollars per million British thermal units ($/MMBtu). ERCOT shall issue a Market Notice disclosing the name of the ERCOT-selected source for the average daily index prices used to calculate FIP. In the event that the ERCOT-selected source becomes unavailable, or ERCOT determines that the source has become unsuitable for the intended purpose, ERCOT may select a substitute source. ERCOT shall issue a Market Notice disclosing its intent to use a substitute source and the name of the substitute source at least 60 days prior to the beginning of its use, or as soon as practicable.

The effective dates for daily index prices shall be as indicated by the ERCOT-selected source. For validation of Three-Part Supply Offers in the Day-Ahead Market (DAM), Day-Ahead Reliability Unit Commitment (DRUC), and Hourly Reliability Unit Commitment (HRUC) occurring before midnight of the Operating Day, the FIP effective for the prior Operating Day will be used. For all other purposes the effective FIP for the Operating Day will be used. If the Katy Hub index is not available, the effective price for the most recent preceding Operating Day shall be used.

Fuel Oil Price (FOP)

An average of the daily index prices for fuel oil for each Operating Day, plus five cents per gallon, for U.S. Gulf Coast, Houston pipeline No. 2 oil, converted to dollars per million British thermal units ($/MMBtu). The conversion is 0.1385 MMBtu per gallon. The effective dates for daily index prices shall be as indicated in the ERCOT-selected index. In the event, at the time of settlement or calculation of generic costs, that the effective price for a particular Operating Day is not available, the effective price for the most recent preceding Operating Day shall be used.

ERCOT shall issue a Market Notice disclosing the name of the ERCOT-selected source for the average daily index prices used to calculate FOP. In the event that the ERCOT-selected index becomes unavailable, or ERCOT determines that the index has become unsuitable for the intended purpose, ERCOT may select a substitute index source. ERCOT shall issue a Market Notice disclosing its intent to use a substitute index source and the name of the substitute index source at least 60 days prior to the beginning of its use, or as soon as practicable.

Full Interconnection Study (FIS)

The set of studies conducted by a Transmission Service Provider (TSP) for the purpose of identifying any electric system improvements or enhancements required to reliably interconnect generation meeting the requirements of Planning Guide Section 5.2.1, Applicability. These studies may include steady-state studies, system protection (short-circuit) studies, dynamic and transient stability studies, facility studies, and sub-synchronous oscillation studies.

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Generation Entity

The owner of a Generation Resource or Settlement Only Generator (SOG) and, unless otherwise specified in these Protocols, is registered as a Resource Entity.

[NPRR995: Replace the above definition "Generation Entity" with the following upon system implementation:]

Generation Entity

The owner of a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) and, unless otherwise specified in these Protocols, is registered as a Resource Entity.

Generation Resource (*see* Resource)

[NPRR973: Insert the following definition "Generator Step-Up (GSU)" upon system implementation of PR106:]

Generator Step-Up (GSU)

Transformer in a station with generation where the voltage is transformed from the voltage level of the generator terminals to a higher voltage. If the higher voltage is at or above 60 kV, the GSU may also be referred to as a Main Power Transformer (MPT).

Generic Transmission Constraint (GTC)

A transmission constraint made up of one or more grouped Transmission Elements that is used to constrain flow between geographic areas of ERCOT for the purpose of managing stability, voltage, and other constraints that cannot otherwise be modeled directly in ERCOT's powerflow and contingency analysis applications.

Generic Transmission Limit (GTL)

The value of the transmission flow limit associated with a GTC.

Generation To Be Dispatched (GTBD)

A dynamically calculated system total generation MW requirement used by Security-Constrained Economic Dispatch (SCED) for resource dispatch, calculated every four seconds.

Good Utility Practice

Any of the practices, methods, and acts engaged in, or approved by, a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

Governmental Authority

Any federal, state, local, or municipal body having jurisdiction over a Market Participant or ERCOT. A Governmental Authority that is also a Market Participant may not exercise its jurisdiction in any matter that involves the interests of that Market Participant where that matter also involves the interests or responsibilities of any other Market Participant or ERCOT, unless the matter is one in which the Market Participant has exclusive jurisdiction.

Governmental Cybersecurity Oversight Agency

A state or federal agency with cybersecurity oversight responsibility. Cybersecurity oversight includes the review, monitoring, supervision, and/or enforcement of cybersecurity laws, programs, activities, and policies.

Governor

The electronic, digital, or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

Governor Dead-Band

The range of deviations of system frequency (+/-) that produces no Primary Frequency Response.

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High Ancillary Service Limit (HASL)

A dynamically calculated MW upper limit on a Resource to reserve the part of the Resource's capacity committed for Ancillary Service, calculated as described in Section 6.5.7.2, Resource Limit Calculator. HASL is also included in Section 5.7.4.1.1, Capacity Shortfall Ratio Share, Section 6.8.3.1.1, Capacity Shortfall Ratio Share for an LCAP Effective Period, and in the Reliability Unit Commitment (RUC) optimization but is not adjusted for Non-Frequency Responsive Capacity (NFRC) as in Section 6.5.7.2.

[NPRR1013: Delete the above definition "High Ancillary Service Limit (HASL)" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

High Emergency Limit (HEL)

The limit established by the QSE describing the maximum temporary unsustainable energy production capability of a Resource. This limit must be achievable for a time stated by the QSE, but not less than 30 minutes.

High Impact Outage (HIO) (*see* Outage)

High Impact Transmission Element (HITE) (*see* Transmission Element)

High Sustained Limit (HSL)

[NPRR1014: Insert the following definition "High Sustained Limit (HSL) for an Energy Storage Resource (ESR)" upon system implementation:]

> ***High Sustained Limit (HSL) for an Energy Storage Resource (ESR)***
>
> The limit established by the Qualified Scheduling Entity (QSE), expressed as a MW value that may be less than, equal to, or greater than zero, continuously updated in Real-Time. A positive HSL for an ESR describes the maximum sustained energy discharging capability of the ESR. A negative HSL for an ESR describes the minimum temporary energy charging capability of the ESR.

High Sustained Limit (HSL) for a Generation Resource

The limit established by the Qualified Scheduling Entity (QSE), continuously updated in Real-Time, that describes the maximum sustained energy production capability of the Resource.

High Sustained Limit (HSL) for a Load Resource

The limit calculated by ERCOT, using the Qualified Scheduling Entity (QSE)-established Maximum Power Consumption (MPC).

Hotline

The telecommunications capability of the ERCOT Wide Area Network (WAN) reserved for simultaneous communications with all Qualified Scheduling Entities (QSEs) with Resources, or their designated agents, or with all Transmission Operators (TOs).

Hourly Reliability Unit Commitment (HRUC)

Any RUC executed after the DRUC.

Hub

A designated Settlement Point consisting of a Hub Bus or group of Hub Buses and the associated Settlement price calculation methodology prescribed in the definition of the Hub in Section 3.5.2, Hub Definitions. Hubs may only be created by an amendment to Section 3.5.2. The list of Hub Buses and the Settlement price calculation methodology that define a Hub can never be modified, and a Hub, once defined, exists in perpetuity.

Hub Bus

(1) In the Day-Ahead Market (DAM) and Congestion Revenue Right (CRR) Auction, an energized power flow bus or group of energized power flow buses are defined as a single element in the Hub definition. The Locational Marginal Price (LMP) of the Hub Bus is the simple average of the LMPs assigned to each energized power flow bus in the Hub Bus. If all power flow buses within a Hub Bus are de-energized, the LMP of the Hub does not include the de-energized Hub Bus. If power flow buses within a Hub Bus are de-energized under contingency, the disconnected MWs are redistributed among remaining energized power flow buses. This is used solely for calculating the prices of existing Hub Buses defined in Section 3.5.2, Hub Definitions; or

(2) In the Real-Time Market (RTM), an energized Electrical Bus or group of energized Electrical Buses defined as a single element in the Hub definition. The LMP of the Hub Bus is the simple average of the LMPs assigned to each energized Electrical Bus in the Hub Bus. If all Electrical Buses within a Hub Bus are de-energized, the LMP of the Hub does not include the de-energized Hub Bus. This is used solely for calculating the prices of existing Hub Buses defined in Section 3.5.2.

Hub LMP (see Locational Marginal Price)

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Independent Market Information System Registered Entity (IMRE)

A Market Participant that has signed the Standard Form Market Participant Agreement (as provided for in Section 22, Attachment A, Standard Form Market Participant Agreement), and has completed applicable registration and approval for the sole purpose of accessing the MIS Secure Area.

Independent Market Monitor (IMM)

The Entity selected to monitor the wholesale electric market pursuant to the Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 39.1515 (Vernon 1998 & Supp. 2007) and P.U.C SUBST. R. 25.365, Independent Market Monitor.

Independent Organization

An independent organization as defined in the Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2007)

Initial Energization

The first time a Generation Resource or Settlement Only Generator (SOG) facility's equipment connects to the ERCOT System during commissioning.

[NPRR995: Replace the above definition "Initial Energization" with the following upon system implementation:]

Initial Energization

The first time a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) facility's equipment connects to the ERCOT System during commissioning.

Initial Synchronization

The first time a Generation Resource or Settlement Only Generator (SOG) facility's new equipment injects power to the ERCOT System during commissioning.

[NPRR995: Replace the above definition "Initial Synchronization" with the following upon system implementation:]

Initial Synchronization

The first time a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) facility's new equipment injects power to the ERCOT System during commissioning.

Interconnecting Entity (IE)

Any Entity that has submitted a Generation Interconnection or Change Request Application for a Generation Resource or Settlement Only Generator (SOG) and meets the requirements of Planning Guide Section 5.2.1, Applicability.

[NPRR995: Replace the above definition "Interconnecting Entity (IE)" with the following upon system implementation:]

Interconnecting Entity (IE)

Any Entity that has submitted a Generation Interconnection or Change Request Application for a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) and meets the requirements of Planning Guide Section 5.2.1, Applicability.

Intermittent Renewable Resource (IRR) (*see* Resource Attribute)

Interval Data Recorder (IDR)

A metering device that is capable of recording energy in each Settlement Interval under Section 9, Settlement and Billing, and Section 10, Metering.

Interval Data Recorder (IDR) Meter

An IDR where the ESI ID is required to be assigned a BUSIDRRQ Load Profile Type code and data is submitted in accordance with Section 10.3.3.3, Submission of Settlement Quality Meter Data to ERCOT.

Interval Data Recorder (IDR) Meter Data Threshold

The percentage of IDR Meter data, by Meter Reading Entity (MRE), that must be available before ERCOT will perform a True-Up Settlement as set forth in Section 9.5.8, RTM True-Up Statement.

Interval Data Recorder (IDR) Mandatory Installation Requirements

The kW (kVA) level at which the installation of an IDR is required for Settlement purposes as set forth in Section 18.6.1, Interval Data Recorder Mandatory Installation Requirements.

Intra-Hour Load Forecast (IHLF)

The Load forecast in five minute increments.

Intra-Hour PhotoVoltaic Power Forecast (IHPPF)

The forecast of PhotoVoltaic (PV) generation in MW in five minute increments.

Intra-Hour Wind Power Forecast (IHWPF)

The forecast of wind generation in MW in five minute increments.

Invoice

A notice for payment or credit due rendered by ERCOT.

Invoice Recipient

A Market Participant that receives an Invoice from ERCOT.

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Level I Maintenance Outage (*see* Outage)

Level II Maintenance Outage (*see* Outage)

Level III Maintenance Outage (*see* Outage)

Limited Impact Remedial Action Scheme (RAS) (*see* Remedial Action Scheme (RAS))

Load

The amount of energy in MWh delivered at any specified point or points on a system.

Wholesale Storage Load (WSL)

Energy that is separately metered from all other Facilities to charge a technology that is capable of storing energy and releasing that energy at a later time to generate electric energy. WSL includes losses for the energy conversion process that are captured by the WSL EPS Meter. WSL is limited to the following technologies: batteries, flywheels, compressed air energy storage, pumped hydro-electric power, electro chemical capacitors, and thermal energy storage associated with turbine inlet chilling.

[PIR003: ERCOT Protocol Interpretation of Wholesale Storage Load (WSL):]

On June 11, 2013, ERCOT issued a Protocol Interpretation on the definition of Wholesale Storage Load (WSL) – providing guidance on which facilities are eligible for Settlement treatment under WSL. *See* Market Notice M-A061113-1, Protocol Interpretation Request – Wholesale Storage Load, at https://www.ercot.com/mktrules/nprotocols/pir_process for full details of the Protocol Interpretation of WSL.

[PIR004: ERCOT Protocol Interpretation of Wholesale Storage Load (WSL):]

On August 16, 2016, ERCOT issued a Protocol Interpretation on the definition of Wholesale Storage Load (WSL) – providing additional guidance on which facilities are eligible for Settlement treatment under WSL. *See* Market Notice M-A081616-01, Protocol Interpretation Request – Wholesale Storage Load, at https://www.ercot.com/mktrules/nprotocols/pir_process for full details of the Protocol Interpretation of WSL.

Load Frequency Control (LFC)

The deployment of those Generation Resources that are providing Regulation Service to ensure that system frequency is maintained within predetermined limits and the deployment of those Generation Resources that are providing Responsive Reserve (RRS) when necessary as backup regulation. LFC does not include the deployment of Responsive Reserve by Load Resources when deployed as a block under Energy Emergency Alert (EEA) procedures.

[NPRR863: Replace the above definition "Load Frequency Control (LFC)" with the following upon system implementation:]

Load Frequency Control (LFC)

The deployment of those Controllable Load Resources and Generation Resources that are providing Regulation Service to ensure that system frequency is maintained within predetermined limits and the deployment of those Controllable Load Resources and Generation Resources that are providing ERCOT Contingency Reserve Service (ECRS) when necessary as backup regulation. LFC does include the deployment of Responsive Reserve

(RRS) (manual) and ECRS from Generation Resources and Controllable Load Resources. LFC does not include the deployment of ECRS or RRS by Load Resources when deployed as a block under Energy Emergency Alert (EEA) procedures.

Load Profile

A representation of the energy usage of a group of Customers, showing the Demand variation on an hourly or sub-hourly basis.

Load Profile ID

The Load Profile designation string that contains, the Load Profile Type Code, the Weather Zone Code, the Meter Data Type Code, the Weather Sensitivity Code, and the Time-Of-Use Schedule Code. An example of all Load Profile IDs are located in the Load Profiling Guide, Appendix D, Profile Decision Tree.

Load Profile Models

Processes that use analytical modeling techniques to create Load Profiles.

Load Profile Segment

A sub-classification of a Load Profile Group. High Winter Ratio (HWR) is an example. Together, the Load Profile Group and the Load Profile Segment form the Load Profile Type.

Load Profile Type

A classification of a group of Customers having similar energy usage patterns and that are assigned the same Load Profile.

Load Profiling

The set of processes used to develop and create Load Profiles.

Load Profiling Methodology

The fundamental basis on which Load Profiles are created. The implementation of a Load Profiling Methodology may require statistical Sampling, engineering methods, econometric modeling, or other approaches.

Load Ratio Share

The ratio of an Entity's AML to total ERCOT AML for an interval.

Load Resource (*see* Resource)

Load Serving Entity (LSE)

An Entity that sells energy to Customers or Wholesale Customers and that has registered as an LSE with ERCOT. LSEs include Competitive Retailers (which includes REPs) and NOIEs that serve Load and ELSEs.

Load Zone

(1) In the Day-Ahead Market (DAM) and Congestion Revenue Right (CRR) Auction, a group of power flow buses assigned to the same zone under Section 3.4, Load Zones. Every power flow bus in ERCOT with a Load must be assigned to a Load Zone for Settlement purposes.

(2) In the Real-Time Market (RTM), a group of Electrical Buses assigned to the same zone under Section 3.4. Every Electrical Bus in ERCOT with a Load must be assigned to a Load Zone for Settlement purposes.

(3) A Non-Opt-In Entity (NOIE) Load Zone is a type of Load Zone.

Load Zone LMP (*see* Locational Marginal Price)

Locational Marginal Price (LMP)

The offer and/or bid-based marginal cost of serving the next increment of Load at an Electrical Bus, which marginal cost is produced by the DAM process or by the SCED process.

Hub LMP

The price calculated for a Hub for each SCED interval according to the formula in Section 6.6.1.5, Hub LMPs, using LMPs at the Electrical Buses included in the Hub.

Load Zone LMP

The price calculated for a Load Zone for each SCED interval according to the formula in Section 6.6.1.4, Load Zone LMPs, using State Estimator Load data and LMPs at the Electrical Buses included in the Load Zone.

Low Ancillary Service Limit (LASL)

A dynamically calculated MW lower limit on a Resource to maintain the ability of the Resource to provide committed Ancillary Service.

> ***[NPRR1013: Delete the above definition "Low Ancillary Service Limit (LASL)" upon system implementation of the Real-Time Co-Optimization (RTC) project.]***

Low Emergency Limit (LEL)

The limit established by the QSE describing the minimum temporary unsustainable energy production capability of a Resource. This limit must be achievable for a period of time indicated by the QSE but not less than 30 minutes.

Low Power Consumption (LPC)

For a Load Resource, the limit established by the QSE, continuously updated in Real-Time, that describes the minimum sustained power consumption of a Load Resource. The LPC shall be a non-negative number in MW.

Low Sustained Limit (LSL)

> ***[NPRR1014: Insert the following definition "Low Sustained Limit (LSL) for an Energy Storage Resource (ESR)" upon system implementation:]***
>
> ***Low Sustained Limit (LSL) for an Energy Storage Resource (ESR)***
>
> The limit established by the Qualified Scheduling Entity (QSE), expressed as a MW value that may be less than, equal to, or greater than zero, continuously updated in Real-Time. A negative LSL for an ESR describes the maximum sustained energy charging capability of the ESR. A positive LSL for an ESR describes the minimum temporary energy discharging capability of the ESR.

Low Sustained Limit (LSL) for a Generation Resource

The limit established by the Qualified Scheduling Entity (QSE), continuously updatable in Real-Time, that describes the minimum sustained energy production capability of a Resource.

Low Sustained Limit (LSL) for a Load Resource

The limit calculated by ERCOT, using the Qualified Scheduling Entity (QSE)-established Low Power Consumption (LPC).

Low System-Wide Offer Cap (LCAP) Effective Period

The period in which the System-Wide Offer Cap (SWCAP) is set to the LCAP.

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[NPRR973: Insert the following definition "Main Power Transformer (MPT)" upon system implementation of PR106:]

Main Power Transformer (MPT)

Transformer in a station with generation where voltage is transformed from a voltage lower than 60 kV to a voltage at or above 60 kV. If the voltage lower than 60 kV is the voltage level of the generator terminals, the MPT may also be referred to as a Generator Step-Up (GSU).

Maintenance Outage (*see* Outage)

Make-Whole Charge

A charge made by ERCOT to a QSE for a Resource to recapture all or part of the revenues received by a QSE that exceed the Make-Whole Payment for a Resource.

Make-Whole Payment

A payment made by ERCOT to a Qualified Scheduling Entity (QSE) for a Resource to reimburse a QSE for allowable startup and minimum energy costs of a Resource not recovered in energy revenue when a Resource is committed by Reliability Unit Commitment (RUC) and the QSE has not elected to opt out of RUC Settlement, or when a Resource is committed by the Day-Ahead Market (DAM).

[NPRR1013: Replace the definition "Make-Whole Payment" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Make-Whole Payment

A payment made by ERCOT to a Qualified Scheduling Entity (QSE) for a Resource to reimburse a QSE for allowable startup and minimum energy costs of a Resource not recovered in energy or Ancillary Service revenue when a Resource is committed by Reliability Unit Commitment (RUC) and the QSE has not elected to opt out of RUC Settlement, or when a Resource is committed by the Day-Ahead Market (DAM).

Mandatory Installation Threshold

A peak demand greater than 700 kW (or 700 kVA).

Market Clearing Price for Capacity (MCPC)

The hourly price for Ancillary Service capacity awarded in the Day-Ahead Market (DAM) or a Supplemental Ancillary Services Market (SASM).

[NPRR1013: Replace the definition "Make-Whole Payment" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Market Clearing Price for Capacity (MCPC)

The price for Ancillary Service capacity awarded in the Day-Ahead Market (DAM) or the Real-Time Market (RTM).

Market Information System (MIS)

An electronic communications interface established and maintained by ERCOT that enables Market Participants, as a group or individually, to access certain information through the use of authenticated credentials.

Market Information System (MIS) Certified Area

The portion of the MIS that is available only to a specific Market Participant.

Market Information System (MIS) Secure Area

The portion of the MIS that is available only to registered Market Participants.

Market Notice

A notice required by the Protocols or any Other Binding Document, or at ERCOT's discretion, regarding market-relevant information that shall be communicated through ERCOT publicly-subscribed electronic distribution channels.

Market Participant

An Entity, other than ERCOT, that engages in any activity that is in whole or in part the subject of these Protocols, regardless of whether that Entity has signed an Agreement with ERCOT. Examples of such an Entity include but are not limited to the following:

(a) Load Serving Entity (LSE);

(b) Qualified Scheduling Entity (QSE);

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

(d) Congestion Revenue Right (CRR) Account Holder;

(e) Resource Entity;

(f) Independent Market Information System Registered Entity (IMRE); and

(g) Renewable Energy Credit (REC) Account Holder.

[NPRR857: Replace the above definition "Market Participant" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Market Participant

An Entity, other than ERCOT, that engages in any activity that is in whole or in part the subject of these Protocols, regardless of whether that Entity has signed an Agreement with ERCOT. Examples of such an Entity include but are not limited to the following:

(a) Load Serving Entity (LSE);

(b) Qualified Scheduling Entity (QSE);

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

(d) Direct Current Tie Operator (DCTO);

(e) Congestion Revenue Right (CRR) Account Holder;

(f) Resource Entity;

(g) Independent Market Information System Registered Entity (IMRE); and

(h) Renewable Energy Credit (REC) Account Holder.

Market Restart

The processes by which ERCOT market-related systems and activities are returned to normal operations during and/or following a Market Suspension.

Market Segment

The segments defined in Article 2 of the ERCOT Bylaws.

Market Suspension

The time period during which market-related systems and activities are terminated due to a triggering event that disables all, or a significant portion of, the necessary data and/or infrastructure for operations of those systems and markets. Such triggering events may include, but are not limited to, Blackouts, Partial Blackouts, and Force Majeure Events.

Mass Transition

The transition of ESI IDs from one CR to a Provider of Last Resort (POLR) or designated CR, or from one TDSP to another TDSP, in a quantity or within a timeframe identified by Applicable Legal Authority.

Master Qualified Scheduling Entity (QSE) (*see* Qualified Scheduling Entity (QSE))

Maximum Daily Resource Planned Outage Capacity

The aggregate maximum MW of Resource Planned Outages that will be approved by ERCOT for any time period within a given day, calculated pursuant to Section 3.1.6.13, Maximum Daily Resource Planned Outage Capacity.

Maximum Power Consumption (MPC)

For a Load Resource, the limit established by the QSE, continuously updated in Real-Time, that describes the maximum sustained power consumption of a Load Resource. The MPC shall be a positive number in MW.

Messaging System

The ERCOT-to-QSE communications system used to send Real-Time notices and Dispatch Instructions to QSEs.

Meter Data Acquisition System (MDAS)

The system used to obtain revenue quality meter data from EPS meters and Settlement Quality Meter Data from TSPs and DSPs for Settlement and to populate the DAS and Data Archive.

Meter Reading Entity (MRE)

A TSP or DSP that is responsible for providing ERCOT with ESI ID level consumption data as defined in Section 19, Texas Standard Electronic Transaction. In the case of an EPS Meter or ERCOT-populated ESI ID data (such as Generation Resource site Load), ERCOT will be identified as the MRE in ERCOT systems.

Metering Facilities

Revenue Quality Meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication Facilities and other related local equipment intended to supply ERCOT settlement quality data.

Minimum-Energy Offer

An offer for the costs incurred by a Resource in producing energy at the Resource's LSL expressed in \$/MWh.

Minimum Point-to-Point (PTP) Option Bid Price

A value of \$0.010 representing the minimum price that can be submitted into the CRR Auction for a PTP Option bid.

Minimum Reservation Price

The lowest price that a seller is willing to accept.

Mitigated Offer Cap (MOC)

An upper limit on the price of an offer as detailed in Section 4.4.9.4.1, Mitigated Offer Cap.

[NPRR826: Replace the above definition "Mitigated Offer Cap (MOC)" with the following upon system implementation:]

Mitigated Offer Cap (MOC)

An upper limit on the price of an offer as detailed in Section 4.4.9.4.1, Mitigated Offer Cap, and Section 4.4.9.4.3, Mitigated Offer Cap for RMR Resources.

Mitigated Offer Floor

A lower limit on the price of an offer as detailed in Section 4.4.9.4.2, Mitigated Offer Floor.

Mitigation Plan (*see* Constraint Management Plan)

Mothballed Generation Resource (*see* Resource Attribute)

Move-In Request

A request submitted by a CR on behalf of a Customer to initiate service at a Premise with the requesting CR.

Move-Out Request

A request submitted by a CR on behalf of a Customer to terminate service at a Premise with the requesting CR.

Municipally Owned Utility (MOU)

A utility owned, operated, and controlled by a nonprofit corporation, the directors of which are appointed by one or more municipalities, or a utility owned, operated, or controlled by a municipality.

Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ Interval

Data Recorder (IDR)

An IDR that is not assigned a BUSIDRRQ Load Profile Type and is located in an MOU or an EC area that is offering Customer Choice. Data submittal for these recorders will be as per Retail Market Guide, Appendix G, ERCOT Specified File Format for Submission of Interval Data for Advanced Metering Systems.

Must-Run Alternative (MRA)

A resource operated under the terms of an Agreement with ERCOT as an alternative to a Reliability Must-Run (RMR) Unit.

[NPRR885 and NPRR995: Replace applicable portions of the above definition "Must-Run Alternative (MRA)" with the following upon system implementation:]

Must-Run Alternative (MRA)

A resource operated under the terms of an Agreement with ERCOT as an alternative to a Reliability Must-Run (RMR) Unit. An MRA may be one of the following:

Generation Resource MRA

A generator that is registered with ERCOT as a Generation Resource that is dispatchable in Security-Constrained Economic Dispatch (SCED) and is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT.

Other Generation MRA

Unregistered generation, or generation registered with ERCOT that is not dispatchable in Security-Constrained Economic Dispatch (SCED), that is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT. An Other Generation MRA may include, but is not limited to, Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Distributed Generation (DG).

Demand Response MRA

A Load providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT by reducing energy consumption in response to an ERCOT instruction. A Demand Response MRA may be an unregistered Load or a registered Load Resource other than a Controllable Load Resource.

Weather-Sensitive MRA

A type of Must-Run Alternative (MRA) Service in which a Demand Response MRA provides MRA Service only after meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1, Emergency Response Service Procurement.

[NPRR885: Insert the following definition "Must-Run Alternative (MRA) Contracted Hour(s)" upon system implementation:]

Must-Run Alternative (MRA) Contracted Hour(s)

The hour(s) during which an MRA is contracted under an MRA Agreement to provide MRA Service.

[NPRR885: Insert the following definition "Must-Run Alternative (MRA) Contracted Month(s)" upon system implementation:]

Must-Run Alternative (MRA) Contracted Month(s)

The month(s) during which an MRA is contracted under an MRA Agreement to provide MRA Service.

[NPRR885: Insert the following definition "Must-Run Alternative (MRA) Service" upon system implementation:]

Must-Run Alternative (MRA) Service

The use by ERCOT, under contracts with Qualified Scheduling Entities (QSEs), of capacity and energy from MRAs as an alternative to Reliability Must-Run (RMR) Service.

[NPRR885: Insert the following definition "Must-Run Alternative (MRA) Site" upon system implementation:]

Must-Run Alternative (MRA) Site

An individually metered component of an aggregated MRA.

[NPRR1026 and NPRR1077: Insert applicable portions of the following definition "MW Injection" upon system implementation:]

MW Injection

The instantaneous Megawatt (MW) energy injected into the ERCOT System as measured at the Point of Interconnection (POI) or Point of Common Coupling (POCC).

[NPRR1026 and NPRR1077: Insert applicable portions of the following definition "MW Withdrawal" upon system implementation:]

MW Withdrawal

The instantaneous Megawatt (MW) energy withdrawn from the ERCOT System as measured at the Point of Interconnection (POI) or Point of Common Coupling (POCC).

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Net Dependable Capability

The maximum sustained capability of a Resource as demonstrated by performance testing.

Net Generation

Gross generation less station auxiliary Load or other internal unit power requirements metered at or adjusted to the POI with the ERCOT Transmission Grid at the common switchyard.

Network Operations Model

A representation of the ERCOT System providing the complete physical network definition, characteristics, ratings, and operational limits of all elements of the ERCOT Transmission Grid and other information from Transmission Service Providers (TSPs), Resource Entities, and Qualified Scheduling Entities (QSEs).

[NPRR857: Replace the above definition "Network Operations Model" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Network Operations Model

A representation of the ERCOT System providing the complete physical network definition, characteristics, ratings, and operational limits of all elements of the ERCOT Transmission Grid and other information from Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), Resource Entities, and Qualified Scheduling Entities (QSEs).

Network Security Analysis

A processor used by ERCOT to monitor Transmission Elements in the ERCOT Transmission Grid for limit violations and to verify Electrical Bus voltage limits to be within a percentage tolerance as outlined in the Operating Guides.

Non-Competitive Constraint

A contingency and limiting Transmission Element pair or group of Transmission Elements associated with a GTC that is not determined to be a Competitive Constraint under the process defined in Section 3.19, Constraint Competitiveness Tests.

Non-Frequency Responsive Capacity (NFRC)

The telemetered portion of a Generation Resource's High Sustained Limit (HSL) that represents the sustainable non-Dispatched power augmentation capability from duct firing, inlet air cooling, auxiliary boilers, or other methods which does not immediately respond, arrest, or stabilize frequency excursions during the first minutes following a disturbance without secondary frequency response or instructions from ERCOT.

[NPRR1013: Delete the above definition "Non-Frequency Responsive Capacity (NFRC)" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Non-Metered Load

Load that is not required to be metered by applicable transmission or distribution tariff.

Non-Opt-In Entity (NOIE)

An EC or MOU that does not offer Customer Choice.

Non-Opt-In Entity (NOIE) Load Zone

A Load Zone established by a NOIE or a group of NOIEs using a one-time NOIE election.

Non-Spinning Reserve (Non-Spin)

An Ancillary Service that is provided through use of the part of Off-Line Generation Resources that can be synchronized and ramped to a specified output level within 30 minutes (or Load Resources that can be interrupted within 30 minutes) and that can operate (or Load Resources that can be interrupted) at a specified output level for at least four consecutive hours. Non-Spin may also be provided from unloaded On-Line capacity that meets the 30-minute response requirements, that is reserved exclusively for use for this service and that can be sustained at a specified level for at least four consecutive hours.

Non-Wholesale Storage Load (WSL) Energy Storage Resource (ESR) Charging Load

The metered or calculated charging Load withdrawn by an Energy Storage Resource (ESR) that is not receiving Wholesale Storage Load (WSL) treatment.

[NPRR995: Insert the following definition "Non-Wholesale Storage Load (WSL) Settlement Only Charging Load" upon system implementation:]

Non-Wholesale Storage Load (WSL) Settlement Only Charging Load

The metered or calculated charging Load withdrawn by a Settlement Only Distribution Energy Storage System (SODESS) or Settlement Only Transmission Energy Storage System (SOTESS) that is not receiving Wholesale Storage Load (WSL) treatment.

Normal Ramp Rate

The rate of change (up and down) in MW per minute of a Resource, which is specified by the QSE to ERCOT by up to ten segments; each segment represents a single MW per minute value (across the capacity of the Resource) that describe the available rate of change for the given range (between HSL and LSL) of generation or consumption of a Resource. In Real-Time SCED Dispatch, the up and down Normal Ramp Rates are telemetered by the QSE to ERCOT and represent the total capacity (in MW) that the Resource can change from its current actual generation or consumption within the next five minutes divided by five.

Normal Rating (*see* Rating)

North American Electric Reliability Corporation (NERC) Regional Entity

An Entity with delegated authority from the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC) to propose and enforce NERC Reliability Standards in the ERCOT Region.

Notice or Notification

The sending of information by an Entity to Market Participants, ERCOT, or others, as called for in these Protocols. Notice or Notification may be sent by electronic mail, facsimile transmission, or U.S. mail.

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Off-Line

The status of a Resource that is not synchronously interconnected to the ERCOT System.

Oklaunion Exemption

The export schedules from the Public Service Company of Oklahoma, the Oklahoma Municipal Power Authority, and the AEP Texas North Company for their share of the Oklaunion Resource over the North DC Tie that are not treated as Load connected at transmission voltage, are not subject to any of the fees described in Section 4.4.4, DC Tie Schedules, and are limited to the actual net output of the Oklaunion Resource.

[NPRR1054: Delete the above definition "Oklaunion Exemption" upon system implementation.]

On-Line

The status of a Resource that is synchronously interconnected to the ERCOT System.

On-Peak Hours

Hours ending in 0700 to 2200 CPT from Monday through Friday excluding NERC holidays.

Operating Condition Notice (OCN)

The first of three levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

Operating Day

The day, including hours ending 0100 to 2400, during which energy flows.

Operating Hour

A full clock hour during which energy flows.

Operating Period

A two-hour period comprised of the Operating Hour and the clock hour preceding the Operating Hour.

Operating Reserve Demand Curve (ORDC)

A curve that represents the value of reserves at different reserve levels based on the probability of reserves falling below the minimum contingency level and the Value of Lost Load (VOLL), as further described in the Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder.

[NPRR1013: Delete the above definition "Operating Reserve Demand Curve (ORDC)" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Opportunity Outage (*see* Outage)

[NPRR1092: Insert the following definition "Opt Out Snapshot" upon system implementation:]

Opt Out Snapshot

A record of a Resource's Current Operating Plan (COP) used to determine whether the Resource will opt out of Reliability Unit Commitment (RUC) Settlement for a block of RUC-Committed Hours. The Opt Out Snapshot is taken at the earlier of:

(a) Two hours prior to the end of the Adjustment Period for the first hour of a contiguous block of RUC-Committed Hours; or

(b) Two hours prior to the beginning of the hour that is at least N hours prior to the first hour of the contiguous block of the RUC-Committed hours, where N is the start time contained in the ERCOT computer system at the time of the RUC execution associated with the RUC instruction corresponding to the Resource's warmth state. If the RUC-Committed Hours are an extension of a Qualified Scheduling Entity (QSE)-Committed Interval either before or after, N will be set to zero. For a Combined Cycle Generation Resource within a Combined Cycle Train, including a RUC to a different configuration with additional capacity, the start time is the start time corresponding to the specific configuration of the RUC-committed Combined Cycle Generation Resource.

Other Binding Documents List

List of Other Binding Documents as managed in paragraph (3) of Section 1.1, Summary of the ERCOT Protocols Document.

Outage

The condition of a Transmission Facility or a portion of a Facility, or Generation Resource that is part of the ERCOT System and defined in the Network Operations Model that has been removed from its normal service, excluding the operations of Transmission Facilities associated with the start-up and shutdown of Generation Resources.

Forced Outage

An Outage initiated by protective relay, or manually in response to an observation by personnel that the condition of equipment could lead to an event, or potential event, that poses a threat to people, equipment, or public safety.

For a Generation Resource, an Outage that requires immediate removal, either through controlled or uncontrolled actions, of all or a portion of the capacity of the Resource from service through automated or manual means. This type of Outage usually results from immediate mechanical/electrical/hydraulic control system trips and operator-initiated actions in response to a Resource's condition.

High Impact Outage (HIO)

A Planned Outage or Rescheduled Outage that interrupts flow on a High Impact Transmission Element (HITE).

Maintenance Outage

An Outage initiated manually to remove equipment from service to perform work on components that could be postponed briefly but that is required to prevent a potential Forced

Outage and that cannot be postponed until the next Planned Outage. Maintenance Outages are classified as follows:

(1) **Level 1 Maintenance Outage** – Equipment that must be removed from service within 24 hours to prevent a potential Forced Outage;

(2) **Level II Maintenance Outage** – Equipment that must be removed from service within seven days to prevent a potential Forced Outage; and

(3) **Level III Maintenance Outage** – Equipment that must be removed from service within 30 days to prevent a potential Forced Outage.

Opportunity Outage

An Outage that may be accepted by ERCOT when a specific Resource is Off-Line due to an Outage.

Planned Outage

An Outage that is planned and scheduled in advance with ERCOT, other than a Maintenance Outage or Opportunity Outage.

Rescheduled Outage

An Outage on a High Impact Transmission Element (HITE) that was originally submitted as a Planned Outage with more than 90-days' notice and approved, but is then rescheduled due to withdrawal of approval by ERCOT of the original Planned Outage or subsequent Rescheduled Outage(s).

Simple Transmission Outage

A Planned Outage or Maintenance Outage of any Transmission Element in the Network Operations Model such that when the Transmission Element is removed from its normal service, absent a Forced Outage of other Transmission Elements, the Outage does not cause a topology change in the LMP calculation and thus cannot cause any LMPs to change with or without the Transmission Element that is suffering the Outage.

Outage Adjustment Evaluation (OAE)

A study performed by ERCOT when it forecasts an inability to meet applicable reliability standards and has exercised all other reasonable options and needs to delay or to cancel and reschedule one or more Resource Outages, unless the issue is due to transmission reliability and is limited to Resources at a single site.

Outage Schedule Adjustment (OSA)

An adjustment to delay or to cancel and reschedule a Resource's Planned Outage that has already been accepted or approved by ERCOT. The OSA is issued by ERCOT to the Qualified Scheduling Entity (QSE) representing the Resource.

Outage Schedule Adjustment (OSA) Period

The portion of a Resource's Planned Outage schedule for which ERCOT issues an OSA. The OSA Period will commence at the planned start time for the Resource Outage, based on the Resource's Planned Outage existing in the Outage Scheduler at the time the Outage Adjustment Evaluation (OAE) is performed, and will end at the time stated in the OSA.

Outage Scheduler

The application that Transmission Service Providers (TSPs) or Qualified Scheduling Entities (QSEs) use to submit Notification of Outages or requests for Outages to ERCOT for approval, acceptance, or rejection.

[NPRR857: Replace the above definition "Outage Scheduler" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Outage Scheduler

The application that Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), or Qualified Scheduling Entities (QSEs) use to submit Notification of Outages or requests for Outages to ERCOT for approval, acceptance, or rejection.

Output Schedule

The self-scheduled output for every five-minute interval of a Resource provided by a QSE before the execution of SCED.

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Partial Blackout (*see* Blackout)

Participating Congestion Revenue Right (CRR) Account Holder (*see* Congestion Revenue Right (CRR) Account Holder)

Peak Load Season

Summer months are June, July, August, and September; winter months are December, January, and February.

PhotoVoltaic (PV)

Of or pertaining to a material or device in which electricity is generated as a result of exposure to light.

PhotoVoltaic Generation Resource (PVGR) (*see* Resource Category)

PhotoVoltaic Generation Resource Production Potential (PVGRPP)

The generation in MWh per hour from a PVGR that could be generated from all available units of that Resource allocated from the 80% probability of exceedance of the Total ERCOT PhotoVoltaic Power Forecast (TEPPF).

Physical Responsive Capability (PRC)

A representation of the total amount of frequency responsive Resource capability On-Line in Real-Time.

Planned Outage (*see* Outage)

Planning Reserve Margin (PRM)

The net of total capacity for the Peak Load Season, less firm peak Load for the Peak Load Season, divided by the firm peak Load for the Peak Load Season (expressed as a percentage).

[NPRR1077: Insert the following definition "Point of Common Coupling (POCC)" upon system implementation:]

Point of Common Coupling (POCC)

Any point where a Distribution Service Provider's (DSP's) facilities are connected to the Facilities of a Customer or a Generation Entity.

Point of Interconnection (POI)

Any physical location where a Generation Entity's Facilities electrically connect to the Transmission Service Provider's (TSP's) Facilities.

[NPRR1098: Replace the above definition "Point of Interconnection (POI)" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Point of Interconnection (POI)

Any physical location where a Generation Entity's Facilities or any Direct Current Tie (DC Tie) Facilities electrically connect to a Transmission Service Provider's (TSP's) Facilities.

Point of Interconnection Bus (POIB)

For a Generation Resource connecting to the ERCOT Transmission System through a Transmission Service Provider (TSP) substation, the Electrical Bus at that TSP substation that is electrically closest to the Generation Resource's Point of Interconnection (POI), or any electrically equivalent Electrical Bus in that substation. For a Generation Resource connecting to the ERCOT Transmission System through a non-TSP substation, the Electrical Bus at that non-TSP substation that is electrically closest to the Generation Resource's POI, or any electrically equivalent Electrical Bus in that substation.

[NPRR1098: Replace the above definition "Point of Interconnection Bus (POIB)" with the following upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Point of Interconnection Bus (POIB)

For a Generation Resource or Direct Current Tie (DC Tie) connecting to the ERCOT Transmission System through a Transmission Service Provider (TSP) substation, the Electrical

Bus at that TSP substation that is electrically closest to the Generation Resource's or DC Tie's Point of Interconnection (POI), or any electrically equivalent Electrical Bus in that substation. For a Generation Resource connecting to the ERCOT Transmission System through a non-TSP substation, the Electrical Bus at that non-TSP substation that is electrically closest to the Generation Resource's POI, or any electrically equivalent Electrical Bus in that substation.

Point-to-Point (PTP) Obligation (*see* Congestion Revenue Right (CRR))

Point-to-Point (PTP) Obligation with Links to an Option (*see* Congestion Revenue Right (CRR))

Point-to-Point (PTP) Option (*see* Congestion Revenue Right (CRR))

Point-to-Point (PTP) Option Award Charge

A charge placed on each PTP Option bid awarded where the clearing price for the PTP Option bid awarded is less than the Minimum PTP Option Bid Price as further described in Section 7.7.1, Determination of the PTP Option Award Charge.

Power System Stabilizer (PSS)

A device that is installed on Generation Resources to maintain synchronous operation of the ERCOT System under transient conditions.

Pre-Assigned Congestion Revenue Right (PCRR) Nomination Year

The calendar year that is three years after the year containing a PCRR nomination process.

Pre-Contingency Action Plan (PCAP) (*see* Constraint Management Plan)

Premise

A Service Delivery Point or combination of Service Delivery Points that is assigned a single ESI ID for Settlement and registration.

Presidio Exception

The losses associated with keeping the 69 kV line from the Gonzales substation to the ERCOT BLT Point at Presidio constantly energized in order to maintain connectivity and allow for rapid response to contingencies impacting the reliability for Customers in the Presidio area when there is no BLT of Load from the ERCOT Control Area to a non-ERCOT Control Area. The TDSP responsible for the Presidio BLT Point metering shall witness and maintain records of meter verification no less than every four years.

Primary Frequency Response

The immediate proportional increase or decrease in real power output provided by Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Generation Resources, Controllable Load Resources, and the natural real power dampening response provided by Load in response to system frequency deviations. This response is in the direction that stabilizes frequency.

[NPRR989 and NPRR995: Replace applicable portions of the above definition "Primary Frequency Response" with the following upon system implementation:]

Primary Frequency Response

The immediate proportional increase or decrease in real power output provided by Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), Generation Resources, Energy Storage Resources (ESRs), Controllable Load Resources, and the natural real power dampening response provided by Load in response to system frequency deviations. This response is in the direction that stabilizes frequency.

Prior Agreement

Any previous Agreement between an Entity, its Affiliate, or its predecessor in interest and ERCOT about performance under the ERCOT Protocols.

Private Microgrid Island (PMI)

A temporary configuration in which a Resource provides electricity to Customer Load through privately-owned transmission and/or distribution infrastructure when the Resource and Customer Load are disconnected from the ERCOT System due to an Outage on the transmission and/or distribution system.

Private Use Network

An electric network connected to the ERCOT Transmission Grid that contains Load that is not directly metered by ERCOT (i.e., Load that is typically netted with internal generation).

Program Administrator

The Entity approved by the PUCT that is responsible for carrying out the administrative responsibilities for the Renewable Energy Credit Program as set forth in P.U.C. SUBST. R. 25.173.

Protected Information

Information protected from disclosure as described in Section 1, Overview.

Provider of Last Resort (POLR)

The designated CR as defined in the P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR), for default Customer service, and as further described in Section 15.1, Customer Switch of Competitive Retailer.

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Qualified Scheduling Entity (QSE)

A Market Participant that is qualified by ERCOT in accordance with Section 16, Registration and Qualification of Market Participants, for communication with ERCOT for Resource Entities and Load Serving Entities (LSEs) and for settling payments and charges with ERCOT.

Data Agent-Only Qualified Scheduling Entity (QSE)

A limited type of QSE that is registered with ERCOT pursuant to Section 16.2.1.1, Data Agent-Only Qualified Scheduling Entities, for the sole purpose of acting as an agent for a QSE that meets all the criteria of Section 16.2.1, Criteria for Qualification as a Qualified Scheduling Entity, relating to the exchange of certain communications and data over the ERCOT Wide Area Network (WAN), as provided in Nodal Operating Guide Section 7, Telemetry and Communication.

Master Qualified Scheduling Entity (QSE)

A QSE designated by Resource Entities owning or controlling a Generation Resource that has been split into two or more Split Generation Resources as set forth in Section 3.8.1, Split Generation Resources, that provides ERCOT data and dispatch on total Generation Resource basis in accordance with the Protocols.

QSE Level 1

A limited type of QSE that does not represent LSEs or Resource Entities. A QSE Level 1 may participate in the Day-Ahead Market (DAM) by submitting Energy-Only Offers, Energy Bids, Energy Trades, Capacity Trades, Direct Current Tie (DC Tie) Schedules, and DAM Point-to-Point Obligation bids.

QSE Level 2

A limited type of QSE that in addition to QSE Level 1 may represent LSEs. A QSE Level 2 does not represent Resource Entities.

QSE Level 3

A limited type of QSE that in addition to QSE Level 2 may represent Resource Entities. A QSE Level 3 does not participate in Ancillary Service or Emergency Response Service (ERS) markets.

QSE Level 4

A limited type of QSE that in addition to QSE Level 3 may participate in Ancillary Service markets.

Qualified Scheduling Entity (QSE) Clawback Interval

Any QSE-Committed Interval that is part of a contiguous block that includes at least one RUC-Committed Hour unless it is:

(a) QSE-committed in the COP and Trades Snapshot before the first RUC instruction for any RUC-Committed Hour in that contiguous block;

(b) Part of a contiguous block of a QSE-Committed Intervals, at least one of which was committed by the QSE in the COP and Trades Snapshot before the RUC instruction described in paragraph (a) above; or

(c) Part of a contiguous block of QSE-Committed Intervals, at least one of which is a RUC Buy-Back Hour.

[NPRR1013: Replace the definition "Qualified Scheduling Entity (QSE) Clawback Interval" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Qualified Scheduling Entity (QSE) Clawback Interval

Any QSE-Committed Interval that is part of a contiguous block that includes at least one Reliability Unit Commitment (RUC)-Committed Hour unless it is:

(a) QSE-committed in the RUC Snapshot before the first RUC instruction for any RUC-Committed Hour in that contiguous block;

(b) Part of a contiguous block of a QSE-Committed Intervals, at least one of which was committed by the QSE in the RUC Snapshot before the RUC instruction described in paragraph (a) above; or

(c) Part of a contiguous block of QSE-Committed Intervals, at least one of which is a RUC Buy-Back Hour.

Qualified Scheduling Entity (QSE)-Committed Interval

A Settlement Interval for which the QSE for a Resource has committed the Resource without a Reliability Unit Commitment (RUC) instruction to commit it. For Settlement purposes, a Resource with a Current Operating Plan (COP) Resource Status of OFFQS will not be considered as QSE-committed for the Settlement Interval unless that interval has been committed due to a Day-Ahead Market (DAM) award for energy.

Qualifying Facility (QF)

A qualifying small power production facility or qualifying cogeneration facility under regulatory qualification criteria as defined in 16 U.S.C.A. § 796(17)(C) and (18)(B).

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Rating

Conductor/Transformer 2-Hour Rating

The two-hour MVA rating of the conductor or transformer only, excluding substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The conductor or transformer can operate at this rating for two hours without violation of National Electrical Safety Code (NESC) clearances or equipment failure.

Emergency Rating

The two-hour MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature.

The Transmission Element can operate at this rating for two hours without violation of NESC clearances or equipment failure.

15-Minute Rating

The 15-minute MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The Transmission Element can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of a conductor or transformer following a sudden increase in current.

Normal Rating

The continuous MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating indefinitely without damage, or violation of NESC clearances.

Relay Loadability Rating

The MVA rating below which no load-responsive phase-protection relay tripping is expected. The Relay Loadability Rating is calculated based on the trip points of protective devices at the equipment terminals of the affected Transmission Element under a set of operating criteria defined by the Transmission Element owner.

Reactive Power

The product of voltage and the out-of-phase component of alternating current. Reactive Power, usually measured in MVAr, is produced by capacitors, overexcited generators and other capacitive devices and is absorbed by reactors, under-excited generators and other inductive devices.

Real-Time

The current instant in time.

[NPRR1013: Insert the following definition “Real-Time Market (RTM)” upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Real-Time Market (RTM)

A Real-Time, co-optimized market in the Operating Day for Ancillary Service capacity and energy.

Real-Time Market (RTM) Energy Bid

A proposal to buy energy in the RTM at a monotonically non-increasing price with increasing quantity.

Real-Time Market (RTM) Final Statement (*see* Settlement Statement)

Real-Time Market (RTM) Initial Statement (*see* Settlement Statement)

Real-Time Market (RTM) Resettlement Statement (*see* Settlement Statement)

Real-Time Market (RTM) True-Up Statement (*see* Settlement Statement)

Real-Time Off-Line Reserve Price Adder

A Real-Time price adder that captures the value of the opportunity costs of Off-Line reserves based on the defined ORDC as detailed in Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge.

[NPRR1013: Delete the above definition "Real-Time Off-Line Reserve Price Adder" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Real-Time On-Line Reliability Deployment Price

A Real-Time price for each 15-minute Settlement Interval reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.

[NPRR1013: Delete the above definition "Real-Time On-Line Reliability Deployment Price" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Real-Time On-Line Reliability Deployment Price Adder

A Real-Time price adder that captures the impact of reliability deployments on energy prices for each Security-Constrained Economic Dispatch (SCED) process as detailed in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, and Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge.

[NPRR1013: Delete the above definition "Real-Time On-Line Reliability Deployment Price Adder" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Real-Time On-Line Reserve Price Adder

A Real-Time price adder that captures the value of the opportunity costs of On-Line reserves based on the defined ORDC as detailed in Section 6.7.5.

[NPRR1013: Delete the above definition "Real-Time On-Line Reserve Price Adder" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

[NPRR1013: Insert the following definition "Real-Time Reliability Deployment Price" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Real-Time Reliability Deployment Price

Real-Time Reliability Deployment Price for Ancillary Service

A Real-Time price for each 15-minute Settlement Interval determined for each Ancillary Service reflecting the impact of reliability deployments on Ancillary service prices, which is calculated from the Real-Time Reliability Deployment Price Adder for Ancillary Service.

Real-Time Reliability Deployment Price for Energy

A Real-Time price for each 15-minute Settlement Interval reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.

[NPRR1013: Insert the following definition "Real-Time Reliability Deployment Price Adder" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Real-Time Reliability Deployment Price Adder

Real-Time Reliability Deployment Price Adder for Ancillary Service

A Real-Time price adder that captures the impact of reliability deployments on prices for each Ancillary Service for each Security-Constrained Economic Dispatch (SCED) process, as detailed in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders.

Real-Time Reliability Deployment Price Adder for Energy

A Real-Time price adder that captures the impact of reliability deployments on energy prices for each Security-Constrained Economic Dispatch (SCED) process as detailed in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders.

Real-Time Reserve Price for Off-Line Reserves

A Real-Time price calculated for Off-Line reserves for each 15-minute Settlement Interval using the data and formulas as detailed in Section 6.7.5.

[NPRR1013: Delete the above definition "Real-Time Reserve Price for Off-Line Reserves" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

Real-Time Reserve Price for On-Line Reserves

A Real-Time price calculated for On-Line reserves for each 15-minute Settlement Interval using the data and formulas as detailed in Section 6.7.5.

[NPRR1013: Delete the above definition "Real-Time Reserve Price for On-Line Reserves" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

[NPRR1013: Insert the following definition "Real-Time System-Wide Offer Cap (RTSWCAP)" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Real-Time System-Wide Offer Cap (RTSWCAP)

The RTSWCAP shall be determined in accordance with Public Utility Commission of Texas (PUCT) Substantive Rules.

Redacted Network Operations Model

A version of the Network Operations Model, redacted to exclude Private Use Network Load data and the following defined Resource Parameters as applicable:

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Minimum On-Line time;

(d) Minimum Off-Line time;

(e) Hot start time;

(f) Intermediate start time;

(g) Cold start time;

(h) Maximum weekly starts;

(i) Maximum On-Line time;

(j) Maximum daily starts;

(k) Maximum weekly energy;

(l) Hot-to-intermediate time;

(m) Intermediate-to-cold time;

(n) Minimum interruption time;

(o) Minimum restoration time;

(p) Maximum weekly deployments;

(q) Maximum interruption time;

(r) Maximum daily deployments;

(s) Minimum notice time; and

(t) Maximum deployment time.

Regional Planning Group (RPG) Project Review

The evaluation of a proposed transmission project pursuant to the process described in Section 3.11.4, Regional Planning Group Project Review Process.

Regulation Down Service (Reg-Down) (***see*** **Regulation Service**)

Regulation Service

An Ancillary Service that consists of either Regulation Down Service (Reg-Down) or Regulation Up Service (Reg-Up).

Fast Responding Regulation Service (FRRS)

A subset of Regulation Service that consists of either Fast Responding Regulation Down Service (FRRS-Down) or Fast Responding Regulation Up Service (FRRS-Up). Except where otherwise specified, all requirements that apply to Regulation Service also apply to FRRS.

[NPRR1013 and NPRR1014: Delete the above definition "Fast Responding Regulation Service (FRRS)" upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively.]

Regulation Down Service (Reg-Down)

An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available below any Base Point but above the Low Sustained Limit (LSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Down must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource's Maximum Power Consumption (MPC) limit.

[NPRR1013 and NPRR1014: Replace applicable portions of the definition "Regulation Down Service (Reg-Down)" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively:]

Regulation Down Service (Reg-Down)

An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available below any Base Point but above the Low Sustained Limit (LSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. An Energy Storage Resource (ESR) providing Reg-Down must be able to modify its energy withdrawal or injection as deployed for Reg-Down across the full range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Down must be able to increase and decrease Load as deployed within its Ancillary Service award for Reg-Down below the Load Resource's Maximum Power Consumption (MPC) limit.

Fast Responding Regulation Down Service (FRRS-Down)

A subset of Regulation Down Service (Reg-Down) in which the participating Resource provides Reg-Down capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or its detection of a trigger frequency independent of an ERCOT Dispatch Instruction. Except where otherwise specified, all requirements that apply to Reg-Down also apply to FRRS-Down.

[NPRR1013 and NPRR1014: Delete the above definition "Fast Responding Regulation Down Service (FRRS-Down)" upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively.]

Regulation Up Service (Reg-Up)

An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available above any Base Point but below the High Sustained Limit (HSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Up must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Up above the Load Resource's Low Power Consumption (LPC) limit.

[NPRR1013 and NPRR1014: Replace applicable portions of the definition "Regulation Up Service (Reg-Up)" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively:]

Regulation Up Service (Reg-Up)

An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available above any Base Point but below the High Sustained Limit (HSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. An Energy Storage Resource (ESR) providing Reg-Up must be able to modify its energy withdrawal or injection as deployed for Reg-Up across the full range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Up must be able to increase and decrease Load as deployed within its Ancillary Service award for Reg-Up above the Load Resource's Low Power Consumption (LPC) limit.

Fast Responding Regulation Up Service (FRRS-Up)

A subset of Reg-Up in which the participating Resource provides Reg-Up capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or its detection of a trigger frequency independent of an ERCOT Dispatch Instruction. Except where otherwise specified, all requirements that apply to Reg-Up also apply to FRRS-Up.

[NPRR1013 and NPRR1014: Delete the above definition "Fast Responding Regulation Up Service (FRRS-Up)" upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively.]

Regulation Up Service (Reg-Up) (*see* Regulation Service)

Relay Loadability Rating (*see* Rating)

Reliability Monitor

An Entity selected by the Public Utility Commission of Texas (PUCT) to monitor compliance with all state reliability-related laws, rules, and ERCOT procedures, including Protocols, processes, and any other operating standards applicable to the ERCOT Region.

Reliability Must-Run (RMR) Service

An Ancillary Service provided from an RMR Unit under an Agreement with ERCOT.

Reliability Must-Run (RMR) Unit

A Generation Resource operated under the terms of an Agreement with ERCOT that would not otherwise be operated except that it is necessary to provide voltage support, stability or management of localized transmission constraints under Credible Single Contingency criteria where market solutions do not exist.

Reliability Unit Commitment (RUC)

A process to ensure that there is adequate Resource capacity and Ancillary Service capacity committed in the proper locations to serve ERCOT forecasted Load.

Reliability Unit Commitment for Additional Capacity (RUCAC)-Hour

An Operating Hour for which a Combined Cycle Generation Resource is Qualified Scheduling Entity (QSE)-committed and receives a Reliability Unit Commitment (RUC) instruction from

ERCOT to transition to a configuration with additional capacity above the configuration that was QSE-committed.

Reliability Unit Commitment for Additional Capacity (RUCAC)-Interval

A Settlement Interval within the hour for which there is a Reliability Unit Commitment (RUC) instruction from ERCOT for a Combined Cycle Generation Resource to transition to a configuration with additional capacity above the configuration that was Qualified Scheduling Entity (QSE)-committed.

Reliability Unit Commitment (RUC) Buy-Back Hour

An Operating Hour for which a Resource that is not a Reliability Must-Run (RMR) Unit has been committed to come On-Line by a RUC process or RUC Verbal Dispatch Instruction (VDI) and the Resource's Qualified Scheduling Entity (QSE) has chosen to opt out of RUC Settlement in accordance with Section 5.5.2, Reliability Unit Commitment (RUC) Process.

[NPRR1092: Replace the above definition "Reliability Unit Commitment (RUC) Buy-Back Hour" with the following upon system implementation:]

Reliability Unit Commitment (RUC) Buy-Back Hour

An Operating Hour for which a Resource that is not a Reliability Must-Run (RMR) Unit has been committed to come On-Line by a Day-Ahead Reliability Unit Commitment (DRUC) or Hourly Reliability Unit Commitment (HRUC) process and the Resource's Qualified Scheduling Entity (QSE) has chosen to opt out of RUC Settlement in accordance with Section 5.5.2, Reliability Unit Commitment (RUC) Process.

Reliability Unit Commitment (RUC) Cancellation

An ERCOT instruction, prior to breaker close, to cancel a previously issued RUC instruction.

Reliability Unit Commitment (RUC)-Committed Hour

An Operating Hour for which a RUC has committed a Resource to be On-Line and the QSE has not designated a RUC Buy-Back Hour.

Reliability Unit Commitment (RUC)-Committed Interval

A Settlement Interval for which there is a RUC instruction to commit a Resource.

[NPRR1013: Insert the following definition "Reliability Unit Commitment (RUC) Snapshot" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Reliability Unit Commitment (RUC) Snapshot

A record of a Qualified Scheduling Entity's (QSE's) Capacity Trades, Energy Trades, Ancillary Service Positions, Ancillary Service Offers, Direct Current Tie (DC Tie) imports and most recent Current Operating Plan (COP) at the time the snapshot is taken.

Reliability Unit Commitment (RUC) Study Period

As defined under Section 5.1, Introduction.

Remedial Action Plan (RAP) (*see* Constraint Management Plan)

Remedial Action Scheme (RAS)

A scheme designed to detect predetermined ERCOT System conditions and automatically take corrective actions on areas of the ERCOT System that are part of the Bulk Electric System, as that term is defined in the North American Electric Reliability Corporation (NERC) Glossary of Terms Used in NERC Reliability Standards. These corrective actions include, but are not limited to, adjusting or tripping generation (MW and MVAr), tripping Load, or reconfiguring a System(s) to maintain a secure system. RASs do not include under-frequency or under voltage Load shedding, the isolation of fault conditions, or out-of-step relaying (not designed as an integral part of an RAS). RASs shall not be implemented on Interconnection Reliability Operating Limits (IROLs). Additional criteria that are excluded from being classified as RAS are outlined in the Operating Guides.

Limited Impact Remedial Action Scheme (RAS)

A RAS that by inadvertent operation or failure to operate does not cause or contribute to ERCOT System cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Remedial Action Scheme (RAS) Entity

Any Market Participant that owns Facilities that are included in a RAS.

Renewable Energy Credit (REC)

A tradable instrument that represents all of the renewable attributes associated with one MWh of production from a certified renewable generator.

Renewable Energy Credit (REC) Account

An account maintained by ERCOT for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs or Compliance Premiums by a REC Account Holder.

Renewable Energy Credit (REC) Account Holder

An Entity registered with ERCOT to participate in the REC Trading Program.

Renewable Energy Credit (REC) Trading Program

The Renewable Energy Credit Trading program, as described in Section 14, State of Texas Renewable Energy Credit Trading Program, and P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

Renewable Portfolio Standard (RPS)

The amount of capacity required to meet the requirements of Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 39.904 (Vernon 1998 & Supp. 2007) and P.U.C. SUBST. R. 25.173(h).

Renewable Production Potential (RPP)

The maximum generation in MWh per interval from an Intermittent Renewable Resource (IRR) that could be generated from all available units of that Resource. The RPP depends on the renewable energy that can be generated from the available units (wind, solar radiation, or run-of-river water supply), current environmental conditions and the energy conversion characteristics of each unit.

Repowered Facility

An existing facility that has been modernized or upgraded to use renewable energy technology to produce electricity consistent with P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

Rescheduled Outage (*see* Outage)

Reserve Discount Factor (RDF)

A representation of the average amount of system-wide capability that, for whatever reason, is historically undeliverable during periods of high system demand. The RDF will be verified by ERCOT and then approved by the Reliability and Operations Subcommittee (ROS).

Resource

The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term "Resource" used by itself in these Protocols does not include a Settlement Only Generator (SOG) or an Emergency Response Service (ERS) Resource.

[NPRR995: Replace the above definition "Resource" with the following upon system implementation:]

Resource

The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term "Resource" used by itself in these Protocols does not include a Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or an Emergency Response Service (ERS) Resource.

Energy Storage Resource (ESR)

An Energy Storage System (ESS) registered with ERCOT for the purpose of providing energy and/or Ancillary Service to the ERCOT System.

[NPRR1029: Insert the following definition "DC-Coupled Resource upon system implementation:]

DC-Coupled Resource

A type of Energy Storage Resource (ESR) in which an Energy Storage System (ESS) is combined with wind and/or solar generation in the same modeled generation station and interconnected at the same Point of Interconnection (POI), and where these technologies are interconnected within the site using direct current (DC) equipment. The combined technologies are then connected to the ERCOT System using the same direct current-to-alternating current (DC-to-AC) inverter(s). To be classified as a DC-Coupled Resource, the generator(s) and ESS(s) at a site must meet the following conditions:

(1) The ESS component of the Resource must have a nameplate rating of at least ten MW and ten MWh, or the MW rating must equal or exceed 50% of the nameplate MW rating of the inverter; and

(2) All intermittent renewable generators must meet the conditions for aggregation stated in paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, except to the extent any such condition requires the generator to be a Resource.

Distribution Energy Storage Resource (DESR)

An Energy Storage Resource (ESR) connected to the Distribution System that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Greater than one MW that chooses to register as a Resource with ERCOT to participate in the ERCOT markets.

Generation Resource

A generator capable of providing energy or Ancillary Service to the ERCOT System and is registered with ERCOT as a Generation Resource.

Distribution Generation Resource (DGR)

A Generation Resource connected to the Distribution System that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets.

Transmission Generation Resource (TGR)

A Generation Resource connected to the ERCOT transmission system that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets.

Load Resource

A Load capable of providing Ancillary Service to the ERCOT System and/or energy in the form of Demand response and registered with ERCOT as a Load Resource.

Aggregate Load Resource (ALR)

A Load Resource that is an aggregation of individual metered sites, each of which has less than ten MW of Demand response capability and all of which are located within a single Load Zone.

[NPRR1131: Replace the above definition "Aggregate Load Resource (ALR)" with the following upon system implementation:]

Aggregate Load Resource (ALR)

A Controllable Load Resource that is an aggregation of individual metered sites, each of which has less than ten MW of Demand response capability and all of which are located within a single Load Zone.

Controllable Load Resource

A Load Resource capable of controllably reducing or increasing consumption under Dispatch control by ERCOT.

Settlement Only Generator (SOG)

A generator that is settled for exported energy only, but may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or make energy offers. These units are comprised of:

[NPRR995: Delete the above definition "Settlement Only Generator (SOG)" upon system implementation.]

Settlement Only Distribution Generator (SODG)

A generator that is connected to the Distribution System with a rating of:

(1) One MW or less that chooses to register as an SODG; or

(2) Greater than one and up to ten MW that is capable of providing a net export to the ERCOT System and does not register as a Distribution Generation Resource (DGR).

SODGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

[NPRR995: Delete the above definition "Settlement Only Distribution Generator (SODG)" upon system implementation.]

Settlement Only Transmission Generator (SOTG)

A generator that is connected to the ERCOT transmission system with a rating of ten MW or less and is registered with the Public Utility Commission of Texas (PUCT) as a power generation company. SOTGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and may be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

[NPRR995: Delete the above definition "Settlement Only Transmission Generator (SOTG)" upon system implementation.]

Settlement Only Transmission Self-Generator (SOTSG)

A generator that is connected to the ERCOT transmission system with a rating of one MW or more and is registered with the Public Utility Commission of Texas (PUCT) as a self-generator. SOTSGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.3, Modeling of Private Use Networks.

[NPRR995: Delete the above definition "Settlement Only Transmission Self-Generator (SOTSG)" upon system implementation.]

Resource Attribute

Specific qualities associated with various Resources (i.e., specific aspects of a Resource or the services the Resource is qualified to provide).

Aggregate Generation Resource (AGR)

A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are located behind the same Generator Step-Up (GSU) transformer (with a high-side voltage greater than 60 kV).

[NPRR973: Replace the definition "Aggregate Generation Resource (AGR)" above with the following upon system implementation of PR106:]

Aggregate Generation Resource (AGR)

A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are located behind the same Main Power Transformer (MPT).

Black Start Resource

A Generation Resource under contract with ERCOT to provide Black Start Service (BSS).

Combined Cycle Train

The combinations of gas turbines and steam turbines in an electric generation plant that employs more than one thermodynamic cycle. For example, a Combined Cycle Train refers to the combination of gas turbine generators (operating on the Brayton Cycle) with turbine exhaust waste heat boilers and steam turbine generators (operating on the Rankine Cycle) for the production of electric power. In the ERCOT market, Combined Cycle Trains are each registered as a plant that can operate as a Generation Resource in one or more Combined Cycle Generation Resource configurations.

Decommissioned Generation Resource

A Generation Resource for which a Resource Entity has submitted a Notification of Suspension of Operations or a Notification of Change of Generation Resource Designation, for which ERCOT has declined to execute a Reliability Must-Run (RMR) Agreement, and which has been decommissioned and permanently retired.

Dynamically Scheduled Resource (DSR)

A Resource that has been designated by the Qualified Scheduling Entity (QSE), and approved by ERCOT, as a DSR status-type and that follows a DSR Load.

[NPRR1000: Delete the definition "Dynamically Scheduled Resource (DSR)" above upon system implementation.]

Intermittent Renewable Resource (IRR)

A Generation Resource that can only produce energy from variable, uncontrollable Resources, such as wind, solar, or run-of-the-river hydroelectricity.

Intermittent Renewable Resource (IRR) Group

A group of two or more IRRs whose performance in responding to Security-Constrained Economic Dispatch (SCED) Dispatch Instructions will be assessed as an aggregate for Generation Resource Energy Deployment Performance (GREDP) and Base Point Deviation. An IRR Group cannot contain any IRRs that are Split Generation Resources. Additionally, only IRRs that have the same Resource Node can be mapped to an IRR Group. Resource Entities can choose to group IRRs and shall provide the grouping information in a timely manner for ERCOT review prior to the scheduled database loads.

[NPRR1013: Replace the definition "Intermittent Renewable Resource (IRR) Group" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Intermittent Renewable Resource (IRR) Group

A group of two or more IRRs whose performance in responding to Security-Constrained Economic Dispatch (SCED) Dispatch Instructions will be assessed as an aggregate for Generation Resource Energy Deployment Performance (GREDP) and Set Point Deviation. An IRR Group cannot contain any IRRs that are Split Generation Resources. Additionally, only IRRs that have the same Resource Node can be mapped to an IRR Group. Resource Entities can choose to group IRRs and shall provide the grouping information in a timely manner for ERCOT review prior to the scheduled database loads.

Inverter-Based Resource (IBR)

A Resource that is connected to the ERCOT System either completely or partially through a power electronic converter interface.

Mothballed Generation Resource

A Generation Resource for which a Resource Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute a Reliability Must-Run (RMR) Agreement, and which has not been decommissioned and retired.

Quick Start Generation Resource (QSGR)

A Generation Resource that in its cold-temperature state can come On-Line within ten minutes of receiving ERCOT notice and has passed an ERCOT QSGR test that establishes an amount of capacity that can be deployed within a ten-minute period.

Split Generation Resource

Where a Generation Resource has been split to function as two or more independent

Generation Resources in accordance with Section 10.3.2.1, Generation Resource Meter Splitting, and Section 3.10.7.2, Modeling of Resources and Transmission Loads, each such functionality independent Generation Resource is a Split Generation Resource.

Switchable Generation Resource (SWGR)

A Generation Resource that can be connected to either the ERCOT Transmission Grid or a non-ERCOT Control Area.

Resource Category

The generation technology category designated for a Generation Resource in its Resource Registration documentation.

Combined Cycle Generation Resource

A specified configuration of physical Generation Resources (gas and steam turbines), with a distinct set of operating parameters and physical constraints, in a Combined Cycle Train registered with ERCOT.

PhotoVoltaic Generation Resource (PVGR)

A Generation Resource that is powered by PhotoVoltaic (PV) equipment exposed to light. PV equipment may be aggregated together to form a PVGR as set forth in paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads.

Wind-powered Generation Resource (WGR)

A Generation Resource that is powered by wind. Wind turbines may be aggregated together to form a WGR as set forth in paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads.

Resource Commissioning Date

The date on which ERCOT declares that a Resource has completed all qualification testing administered by ERCOT as part of the Resource Interconnection process so that a Resource is approved for participation in ERCOT market operations.

Resource Connectivity Node (*see* Electrical Bus)

Resource Entity

An Entity that owns or controls a Generation Resource, a Settlement Only Generator (SOG), or a Load Resource and is registered with ERCOT as a Resource Entity.

[NPRR989 and NPRR995: Replace applicable portions of the above definition "Resource Entity" with the following upon system implementation:]

Resource Entity

An Entity that owns or controls a Generation Resource, an Energy Storage Resource (ESR), a Settlement Only Generator (SOG), a Settlement Only Energy Storage System (SOESS), or a Load Resource and is registered with ERCOT as a Resource Entity.

Resource ID (RID)

A unique identifier assigned to each Resource used in the registration and Settlements systems managed by ERCOT.

Resource Node

Either a logical construct that creates a virtual pricing point required to model a Combined-Cycle Configuration or an Electrical Bus defined in the Network Operations Model, at which a Settlement Point Price for a Generation Resource or Energy Storage Resource (ESR) is calculated and used in Settlement. All Resource Nodes shall be identified in accordance with the Other Binding Document titled "Procedure for Identifying Resource Nodes."

Resource Parameters

Resource-specific parameters required for use in ERCOT business processes. This is a subset of Resource Registration data that can be changed in the MIS in Real-Time.

Resource Registration

Provision of information required by ERCOT to register Generation Resources, Settlement Only Generators (SOGs), Load Resources, and Energy Storage Resources (ESRs).

[NPRR995: Replace the above definition "Resource Registration" with the following upon system implementation:]

Resource Registration

Provision of information required by ERCOT to register Generation Resources, Settlement Only Generators (SOGs), Load Resources, Settlement Only Energy Storage Systems (SOESSs), and Energy Storage Resources (ESRs).

Resource Status

The operational state of a Resource as provided in Section 3.9, Current Operating Plan (COP).

Responsive Reserve (RRS)

An Ancillary Service that provides operating reserves that is intended to:

(a) Arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using Primary Frequency Response and interruptible Load;

(b) After the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal;

(c) Provide energy or continued Load interruption during the implementation of the Energy Emergency Alert (EEA); and

(d) Provide backup regulation.

[NPRR863: Replace the above definition "Responsive Reserve (RRS)" with the following upon system implementation:]

Responsive Reserve (RRS)

An Ancillary Service that provides operating reserves that are intended to:

(a) Arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using Primary Frequency Response, Fast Frequency Response (FFR), and interruptible Load;

(b) After the first few seconds of a significant frequency deviation, help arrest and stabilize frequency; and

(c) Provide energy or continued Load interruption during the implementation of the Energy Emergency Alert (EEA).

Retail Business Day (*see* Business Day)

Retail Business Hour

Any hour within a Retail Business Day.

Retail Electric Provider (REP)

As defined in P.U.C. SUBST. R. 25.5, Definitions, an Entity that sells electric energy to retail Customers in Texas but does not own or operate generation assets and is not an MOU or EC.

Retail Entity

An MOU, generation and transmission cooperative or distribution cooperative that offers Customer Choice; REP; or IOU that has not unbundled pursuant to Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 39.051 (Vernon 1998 & Supp. 2007).

Revenue Quality Meter

For EPS Meters, a meter that complies with the Protocols and the Settlement Metering Operating Guide. For TSP- or DSP-metered Entities, a meter that complies with Governmental Authority-approved meter standards, or the Protocols and the Operating Guides.

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Sampling

The process of selecting a subset of a population of Customers that statistically represents the entire population.

Scheduled Power Consumption

Expected Load, in MW, reported by a QSE for a Controllable Load Resource pursuant to Section 6.5.5.2, Operational Data Requirements.

Scheduled Power Consumption Snapshot

A snapshot, taken by ERCOT, of the Scheduled Power Consumption provided by the QSE for a Controllable Load Resource at the end of the adjustment period and used in determining the Controllable Load Resource Desired Load.

Season or Seasonal

Winter months are December, January, and February; Spring months are March, April, and May; Summer months are June, July, and August; Fall months are September, October, and November.

Seasonal Operation Period

The period in which a Generation Resource has identified it is available for operation.

Securitization Default Balance

The amount financed by ERCOT pursuant to Public Utility Regulatory Act (PURA) Chapter 39, Restructuring of Electric Utility Industry, Subchapter M, Winter Storm Uri Default Balance Financing, as authorized by the Public Utility Commission of Texas (PUCT), but which may not exceed $800 million.

Securitization Default Charge

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

Securitization Uplift Balance

The amount of money ERCOT securitized under Public Utility Regulatory Act (PURA) Chapter 39, Restructuring of Electric Utility Industry, Subchapter N, Winter Storm Uri Uplift Financing, pursuant to the Debt Obligation Order (DOO) issued by the Public Utility Commission of Texas (PUCT) in PUCT Docket No. 52322, Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order to Finance Uplift Balances Under PURA Chapter 39, Subchapter N, and for a Good Cause Exception.

Securitization Uplift Charge

A charge assessed to a Qualified Scheduling Entity (QSE) that represents an obligated Load Serving Entity (LSE) that will be used to pay the Securitization Uplift Balance, interest charges, and other financing related expenses.

Securitization Uplift Charge Opt-Out Entity

An eligible entity under Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.653(d) (Vernon 1998 & Supp. 2007) (PURA) that qualified to opt-out of paying Securitization Uplift Charges, as documented through the filing of opt-out notices in Public Utility Commission of Texas (PUCT) Project No. 52364, Proceeding for Eligible Entities to File an Opt Out Pursuant to PURA § 39.653(d) and for Load-Serving Entities to File Documentation of Exposure to Costs Pursuant to the Debt Obligation Order in Docket No. 52322, and as addressed in Findings of Fact 38-46 and Ordering Paragraphs 20-25 of the Debt Obligation Order in Docket No. 52322, Application of the Electric Reliability Council of Texas, Inc. For a Debt Obligation Order to Finance Uplift Balances Under PURA Chapter 39, Subchapter N, for an Order Initiating a Parallel Docket, and for a Good Cause Exception.

Security-Constrained Economic Dispatch (SCED)

The determination of desirable Generation Resource output levels using Energy Offer Curves while considering State Estimator output for Load at transmission-level Electrical Buses, Generation Resource limits, and transmission limits to provide the least offer-based cost dispatch of the ERCOT System.

[NPRR1013 and NPRR1014: Replace the definition "Security-Constrained Economic Dispatch (SCED)" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively:]

Security-Constrained Economic Dispatch (SCED)

A process for determining Ancillary Service awards and Base Point instructions for Resources using Energy Offer Curves, Energy Bid/Offer Curves, RTM Energy Bids, Ancillary Service Offers and Ancillary Service Demand Curves. A SCED execution results in Ancillary Service awards and Base Point instructions that maximize bid-based revenues less offer-based costs while considering State Estimator output for Load at transmission-level Electrical Buses, Resource limits, and transmission limits to maximize bid-based revenues less offer-based costs.

Self-Arranged Ancillary Service Quantity

The quantity of an Ancillary Service that a Qualified Scheduling Entity (QSE) secures for itself using Resources represented by that QSE and Ancillary Service Trades.

[NPRR1013: Replace the definition "Self-Arranged Ancillary Service Quantity" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Self-Arranged Ancillary Service Quantity

The quantity of an Ancillary Service that a Qualified Scheduling Entity (QSE) secures for itself in the Day-Ahead Market (DAM) using Resources represented by that QSE and Ancillary Service Trades.

[NPRR1026 and NPRR1077: Insert applicable portions of the following definition "Self-Limiting Facility" upon system implementation:]

Self-Limiting Facility

A modeled generation station that includes one or more Generation Resources, Energy Storage Resources (ESRs), and/or Settlement Only Generators (SOGs) with an established limit on the total MW Injection that is less than the total nameplate capacity of all registered generators or Energy Storage Systems (ESSs) within the Facility. A Facility with one or more ESRs may also have an established limit on the MW Withdrawal that is less than the total nameplate MW Withdrawal rating of all ESRs within the facility.

Self-Schedule

Information for Real-Time Settlement purposes that specifies the amount of energy supply at a specified source Settlement Point used to meet an energy obligation at a specified sink Settlement Point for the QSE submitting the information.

Service Address

The street address associated with an ESI ID as recorded in the Customer Registration Database. This address shall conform to United States Postal Service Publication 28.

Service Delivery Point

The specific point on the system where electricity flows from the TSP or DSP to a Customer.

Settlement

The process used to resolve financial obligations between a Market Participant and ERCOT.

Settlement Calendar

A calendar that provides information on when Settlement Statements and Invoices shall be posted, payment due dates, and dispute deadlines. Additional information is provided in Section 9.1.2, Settlement Calendar.

Settlement Interval

The time period for which markets are settled.

Settlement Invoice

A notice for payment or credit due rendered by ERCOT based on data contained in Settlement Statements.

Settlement Meter

Generation and end-use consumption meters used for allocation of ERCOT charges and wholesale and retail Settlements.

[NPRR995: Insert the following definitions "Settlement Only Energy Storage System (SOESS)", "Settlement Only Distribution Energy Storage System (SODESS)", and "Settlement Only Transmission Energy Storage System (SOTESS)" upon system implementation:]

Settlement Only Energy Storage System (SOESS)

An Energy Storage System (ESS) that is settled for imported/exported energy only, but may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or submit energy offers or bids. These units are comprised of:

Settlement Only Distribution Energy Storage System (SODESS)

An Energy Storage System (ESS) connected to the Distribution System with a rating of:

(1) One MW or less that chooses to register as an SODESS; or

(2) Greater than one and up to ten MW that is capable of providing a net export to the ERCOT System and does not register as a Distribution Energy Storage Resource (DESR).

Settlement Only Transmission Energy Storage System (SOTESS)

An Energy Storage System (ESS) connected to the ERCOT transmission system with a rating of ten MW or less that has not been registered as an Energy Storage Resource (ESR).

[NPRR995: Insert the following definitions "Settlement Only Generator (SOG)", "Settlement Only Distribution Generator (SODG)", "Settlement Only Transmission Generator (SOTG)", and "Settlement Only Transmission Self-Generator (SOTSG)" upon system implementation:]

Settlement Only Generator (SOG)

A generator that is settled for exported energy only, but may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or submit energy offers. These units are comprised of:

Settlement Only Distribution Generator (SODG)

A generator that is connected to the Distribution System with a rating of:

(1) One MW or less that chooses to register as an SODG; or

(2) Greater than one and up to ten MW that is capable of providing a net export to the ERCOT System and does not register as a Distribution Generation Resource (DGR).

SODGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

Settlement Only Transmission Generator (SOTG)

A generator that is connected to the ERCOT transmission system with a rating of ten MW or less and is registered with the Public Utility Commission of Texas (PUCT) as a power generation company. SOTGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and may be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

Settlement Only Transmission Self-Generator (SOTSG)

A generator that is connected to the ERCOT transmission system with a rating of one MW or more and is registered with the Public Utility Commission of Texas (PUCT) as a self-generator. SOTSGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.3, Modeling of Private Use Networks.

Settlement Only Generator (SOG) (*see* Resource)

Settlement Only Distribution Generator (SODG) (*see* Resource)

Settlement Only Transmission Generator (SOTG) (*see* Resource)

Settlement Only Transmission Self-Generator (SOTSG) (*see* Resource)

Settlement Point

A Resource Node, Load Zone, or Hub.

Settlement Point Price

A price calculated for a Settlement Point for each Settlement Interval using LMP data and the formulas detailed in Section 4.6, DAM Settlement, and Section 6.6, Settlement Calculations for the Real-Time Energy Operations.

Settlement Quality Meter Data

Data that has been edited, validated, and is appropriate for ERCOT to use for Settlement and billing purposes.

Settlement Statement

A statement issued by ERCOT reflecting a breakdown of administrative, miscellaneous, and market charges for the applicable market services, as further described in Section 9.2, Settlement Statements for the Day-Ahead Market, and Section 9.5, Settlement Statements for Real-Time Market.

Day-Ahead Market (DAM) Resettlement Statement

The Settlement Statement issued for a particular DAM using corrected Settlement data, in accordance with Section 9.2.5, DAM Resettlement Statement.

Day-Ahead Market (DAM) Statement

The Settlement Statement issued for a particular DAM, as further described in Section 9.2.4, DAM Statement.

Real-Time Market (RTM) Final Statement

The RTM Settlement Statement issued at the end of the 55th day following the Operating Day, as described in Section 9.5.5, RTM Final Statement.

Real-Time Market (RTM) Initial Statement

The first iteration of an RTM Settlement Statement issued for a particular Operating Day, as further described in Section 9.5.4, RTM Initial Statement.

Real-Time Market (RTM) Resettlement Statement

The RTM Settlement Statement using corrected Settlement data, in accordance with Section 9.5.6, RTM Resettlement Statement.

Real-Time Market (RTM) True-Up Statement

The RTM Settlement Statement issued 180 days following the Operating Day, as further described in Section 9.5.8, RTM True-Up Statement.

Shadow Price

A price for a commodity that measures the marginal value of this commodity; that is, the rate at which system costs could be decreased or increased by slightly increasing or decreasing, respectively, the amount of the commodity being made available.

Shift Factor

A measure of the flow on a particular Transmission Element due to a unit injection of power from a particular Electrical Bus to a fixed reference Electrical Bus.

Short-Term PhotoVoltaic Power Forecast (STPPF)

An ERCOT produced hourly 50% probability of exceedance forecast of the generation in MWh per hour from each PVGR that could be generated from all available units of that Resource.

Short-Term Wind Power Forecast (STWPF)

An ERCOT produced hourly 50% probability of exceedance forecast of the generation in MWh per hour from each WGR that could be generated from all available units of that Resource.

Simple Transmission Outage (*see* Outage)

Split Generation Resource (*see* Resource Attribute)

Startup Cost

All costs incurred by a Generation Resource in starting up and reaching Low Sustained Limit (LSL), as described in the Verifiable Cost Manual. The Startup Cost is in dollars per start.

Startup Loading Failure

A type of Forced Outage that results when a Generation Resource is unable to operate at Low Sustained Limit (LSL) at the time scheduled in the Current Operating Plan (COP) which occurs while the unit is ramping up to its scheduled MW output. A Startup Loading Failure ends when the Resource:

(a) Achieves its LSL;

(b) Is scheduled to go Off-Line; or

(c) Ceases the attempt to start the Generation Resource and changes its Resource Status to OUT.

Startup Offer

An offer for all costs incurred by a Generation Resource in starting up and reaching Low Sustained Limit (LSL). The Startup Offer is in dollars per start.

State Estimator

A computational algorithm that uses Real-Time inputs from the network's Supervisory Control and Data Acquisition (SCADA) system that measure the network's electrical parameters, including its topology, voltage, power flows, etc., to estimate electrical parameters (such as line flows and Electrical Bus voltages and Loads) in the ERCOT Transmission Grid. The State Estimator's output is a description of the network and all of the values (topology, voltage, power flow, etc.) to describe each Electrical Bus and line included in the system model.

State Estimator Bus

An electrical node of common voltage at a substation that consists of one or more Electrical Buses tied together with closed breakers or switches.

Study Area

A geographic region designated by ERCOT, separate from a Weather Zone or Load Zone. Study Areas are used primarily for study purposes. Study Areas shall be developed by ERCOT.

Subsynchronous Oscillation (SSO)

Coincident oscillation occurring between two or more Transmission Elements or Generation Resources at a natural harmonic frequency lower than the normal operating frequency of the ERCOT System (60 Hz).

Subsynchronous Resonance (SSR)

Coincident oscillation occurring between Generation Resources and a series capacitor compensated transmission system at a natural harmonic frequency lower than the normal operating frequency of the ERCOT System (60 Hz), including the following types of interactions:

Torsional Interaction

Torsional Interaction is the interplay between mechanical system of a turbine generator and a series compensated transmission system.

Induction Generator Effect (IGE)

An electrical phenomena in which a resonance involving a Generation Resource and a series compensated transmission system results in electrical self-excitation of the Generation Resource at a subsynchronous frequency.

Torque Amplification

An interaction between Generation Resources and a series compensated transmission system in which the response results in higher transient torque during or after disturbances than would otherwise occur.

Subsynchronous Control Interaction (SSCI)

The interaction between a series capacitor compensated transmission system and the control system of Generation Resources.

Subsynchronous Resonance (SSR) Countermeasures

Any equipment or any procedure to mitigate the SSR vulnerability, including but not limited to the following types of countermeasures:

> ***Subsynchronous Resonance (SSR) Protection***
>
> A countermeasure that includes, but is not limited to, disconnecting the affected Generation Resource.
>
> ***Subsynchronous Resonance (SSR) Mitigation***
>
> A countermeasure that includes, but is not limited to, equipment installation, controller adjustment, or a procedure to mitigate the SSR vulnerability without disconnecting the affected Generation Resources.

Sustained Response Period

The period of time beginning ten minutes after ERCOT's issuance of a VDI deploying ERS-10 or 30 minutes after ERCOT's issuance of a VDI deploying ERS-30 and ending with ERCOT's issuance of a VDI releasing ERS Resources from the deployment.

Switch Request

A request submitted by a CR on behalf of a Customer to switch service from the Customer's current CR to the requesting CR.

Switchable Generation Resource (SWGR) (*see* Resource Attribute)

System Lambda

The cost of providing one MWh of energy at the reference Electrical Bus, i.e. the Shadow Price for the power balance constraint, which is equal to the change in the objective function obtained by relaxing the power balance constraint by one MW. The System Lambda is the energy component of LMP at each Settlement Point in ERCOT.

System Operator

An Entity that supervises the collective Transmission Facilities of a power region. This Entity is charged with coordination of market transactions, system-wide transmission planning, and network reliability.

System-Wide Offer Cap (SWCAP)

The SWCAP shall be determined in accordance with Public Utility Commission of Texas (PUCT) Substantive Rules.

[NPRR1013: Delete the above definition "System-Wide Offer Cap (SWCAP)" upon system implementation of the Real-Time Co-Optimization (RTC) project.]

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TSP and DSP Metered Entity

An Entity that meets the requirements of Section 10.2.2, TSP and DSP Metered Entities.

Tangible Net Worth

Total shareholder's equity less goodwill and other intangible assets.

Temporary Outage Action Plan (TOAP) (*see* Constraint Management Plan)

Texas Nodal Market Implementation Date

The date on which ERCOT starts operation of the Texas Nodal Market in compliance with the rules and orders of the Public Utility Commission of Texas (PUCT). Once this date is determined, ERCOT shall post it on the ERCOT website and maintain it on the ERCOT website.

Texas Standard Electronic Transaction (TX SET)

(1) Texas Standard Electronic Transactions (TX SETs) are the electronic data transactions, implementation guides, and applicable external standards that enable and facilitate the retail business processes in the deregulated Texas electric market.

(2) The procedures used to transmit information pertaining to the Customer Registration Database are set forth in Section 19, Texas Standard Electronic Transaction.

Three-Part Supply Offer

An offer made by a QSE for a Generation Resource that it represents containing three components: a Startup Offer, a Minimum-Energy Offer, and an Energy Offer Curve.

Time Of Use (TOU) Meter

A programmable electronic device capable of measuring and recording electric energy in pre-specified time periods. For Load Profiling purposes TOU Metering does not include IDRs.

Time Of Use Schedule (TOUS)

A schedule identifying the Time Of Use period associated with each Settlement Interval. These schedules may include on-peak, off-peak, and shoulder periods.

Transmission Access Service

The use of a TSP's Transmission Facilities for which the TSP is allowed to charge through tariff rates approved by the PUCT.

Transmission and/or Distribution Service Provider (TDSP)

An Entity that is a TSP, a DSP or both, or an Entity that has been selected to own and operate Transmission Facilities and has a PUCT approved code of conduct in accordance with P.U.C. SUBST. R. 25.272, Code of Conduct for Electric Utilities and Their Affiliates.

Transmission Generation Resource (*see* Resource)

Transmission Element

A physical Transmission Facility that is either an Electrical Bus, line, transformer, generator, Load, breaker, switch, capacitor, reactor, phase shifter, or other similar device that is part of the ERCOT Transmission Grid and defined in the ERCOT Network Operations Model.

> ***High Impact Transmission Element (HITE)***
>
> A Transmission Element that may, in certain conditions, result in high congestion risk when taken out-of-service and that is identified as further described in Section 3.1.8, High Impact Transmission Element (HITE) Identification.

Transmission Facilities

(1) Power lines, substations, and associated facilities, operated at 60 kV or above, including radial lines operated at or above 60 kV;

(2) Substation facilities on the high voltage side of the transformer, in a substation where power is transformed from a voltage higher than 60 kV to a voltage lower than 60 kV or is transformed from a voltage lower than 60 kV to a voltage higher than 60 kV; and

(3) The direct current interconnections between ERCOT and the Southwest Power Pool or Comision Federal de Electricidad (CFE).

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) The direct current interconnections between ERCOT and non-ERCOT Control Areas.

Transmission Loss Factor (TLF)

The fraction of ERCOT Load (forecast or actual) that is considered to constitute the ERCOT Transmission Grid losses in a Settlement Interval, based on a linear interpolation (or extrapolation) of the calculated losses in the off-peak and on-peak seasonal ERCOT base cases.

Transmission Losses

The difference between energy put into the ERCOT Transmission Grid and energy taken out of the ERCOT Transmission Grid.

Transmission Operator (TO)

A Transmission and/or Distribution Service Provider (TDSP) designated by itself or another TDSP for purposes of communicating with ERCOT and taking action to preserve reliability of a particular portion of the ERCOT System, as provided in the ERCOT Protocols or Other Binding Documents.

[NPRR1045: Replace the above definition "Transmission Operator (TO)" with the following upon system implementation of NPRR857:]

Transmission Operator (TO)

A Transmission and/or Distribution Service Provider (TDSP) designated by itself, a Direct Current Tie Operator (DCTO), or another TDSP for purposes of communicating with ERCOT and taking action to preserve reliability of a particular portion of the ERCOT System, as provided in the ERCOT Protocols or Other Binding Documents.

Transmission Service

The commercial use of Transmission Facilities.

Transmission Service Provider (TSP)

An Entity under the jurisdiction of the PUCT that owns or operates Transmission Facilities used for the transmission of electricity and provides Transmission Service in the ERCOT Transmission Grid.

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Unaccounted for Energy (UFE)

The difference between total Load for each Settlement Interval, adjusted for applicable Distribution Losses and Transmission Losses, and total ERCOT generation.

Unit Reactive Limit (URL)

The maximum quantity of Reactive Power that a Generation Resource is capable of providing at a 0.95 power factor at its maximum real power capability.

Updated Desired Base Point

A calculated MW value representing the expected MW output of a Generation Resource ramping to a Base Point.

[NPRR1013: Replace the definition "Updated Desired Base Point" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Updated Desired Set Point (UDSP)

A calculated MW value representing the expected MW output of a Resource, as described in Section 6.5.7.4.1, Updated Desired Set Points.

Updated Network Model

A computerized representation of the ERCOT physical network topology, including some Resource Parameters, all of which replicates the forecasted or current network topology of the ERCOT System needed by ERCOT to perform its functions.

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Verbal Dispatch Instruction (VDI)

A Dispatch Instruction issued orally.

Voltage Profile

The set of normally desired Voltage Set Points for those Generation Resources specified in paragraph (2) of Section 3.15, Voltage Support, in the ERCOT System.

[NPRR989: Replace the above definition "Voltage Profile" with the following upon system implementation:]

Voltage Profile

The set of normally desired Voltage Set Points for those Generation Resources or Energy Storage Resources (ESRs) specified in paragraph (2) of Section 3.15, Voltage Support, in the ERCOT System.

Voltage Set Point

The voltage that a Generation Resource is required to maintain at its Point of Interconnection Bus (POIB) and that is initially communicated via the Voltage Profile but may be modified by a Real-Time instruction from ERCOT, the interconnecting Transmission Service Provider (TSP), or that TSP's agent.

[NPRR989: Replace the above definition "Voltage Set Point" with the following upon system implementation:]

Voltage Set Point

The voltage that a Generation Resource or Energy Storage Resource (ESR) is required to maintain at its Point of Interconnection Bus (POIB) and that is initially communicated via the Voltage Profile but may be modified by a Real-Time instruction from ERCOT, the interconnecting Transmission Service Provider (TSP), or that TSP's agent.

Voltage Support Service (VSS)

An Ancillary Service that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits.

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Watch

The third of three levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

Weather Zone

A geographic region designated by ERCOT in which climatological characteristics are similar for all areas within such region.

Weekly Reliability Unit Commitment (WRUC)

An instruction issued by ERCOT prior to 1330 in the Day-Ahead for an Operating Day that reserves a Generation Resource that requires a longer lead time for startup than possible from the DRUC.

Wholesale Customer

A NOIE receiving service at wholesale points of delivery from an LSE other than itself.

Wholesale Storage Load (WSL) (*see* Load)

Wind-powered Generation Resource (WGR) (*see* Resource Category)

Wind-powered Generation Resource Production Potential (WGRPP)

The generation in MWh per hour from a WGR that could be generated from all available units of that Resource allocated from the 80% probability of exceedance of the Total ERCOT Wind Power Forecast (TEWPF).

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2.2 ACRONYMS AND ABBREVIATIONS

4-CP	4-Coincident Peak
AAA	American Arbitration Association
AAN	Advance Action Notice
AASP	Average Aggregated Set Point
ACE	Area Control Error
ACH	Automated Clearing House
ACL	Available Credit Limit
ADR	Alternative Dispute Resolution
AEIC	Association of Edison Illuminating Companies
AGC	Automatic Generation Control
AGR	Aggregate Generation Resource
AIL	Aggregate Incremental Liability
ALA	Applicable Legal Authority
ALR	Aggregate Load Resource
AML	Adjusted Metered Load
AMP	Automatic Mitigation Plan
AMS	Advanced Metering System
ANSI ASC X12	American National Standards Institute Accredited Standards Committee X12
AREP	Affiliated Retail Electric Provider
ARR	Adjusted RPS Requirement
ASDC	Ancillary Service Demand Curve
AVR	Automatic Voltage Regulator
BLT	Block Load Transfer
BSS	Black Start Service

CAO	Control Area Operator
CARD	CRR Auction Revenue Distribution
CCD+	Cash Concentration and Disbursement Plus
CCF	Capacity Conversion Factor
CCN	Certificate of Convenience and Necessity
CCT	Constraint Competitiveness Test
CEO	Chief Executive Officer
CFC	Constant Frequency Control
CFE	Comision Federal de Electricidad
CFTC	Commodity Futures Trading Commission
CIM	Common Information Model
CMLTD	Current Maturities of Long-Term Debt
CMP	Constraint Management Plan
CMZ	Congestion Management Zone
COP	Current Operating Plan
CPS	Control Performance Standard
CPT	Central Prevailing Time
CR	Competitive Retailer
CRR	Congestion Revenue Right
CRRBA	Congestion Revenue Right Balancing Account
CSA	Continuous Service Agreement
CSV	Comma Separated Value
CTX	Corporate Trade Exchange
DAM	Day-Ahead Market
DAS	Data Aggregation System
DASPP	Day-Ahead Settlement Point Price
DASWCAP	Day-Ahead System-Wide Offer Cap
DC	Direct Current
DC Tie	Direct Current Tie
DCAA	Digital Certificate Audit Attestation
DCTO	Direct Current Tie Operator
DESR	Distribution Energy Storage Resource
DG	Distributed Generation
DGR	Distribution Generation Resource
DLC	Direct Load Control
DLF	Distribution Loss Factor
DME	Decision Making Entity
DRG	Distributed Renewable Generation
DRUC	Day-Ahead Reliability Unit Commitment
DSC	Debt Service Coverage
DSP	Distribution Service Provider
DSR	Dynamically Scheduled Resource

[NPRR1000: Delete the acronym "DSR" above upon system implementation.]

DUNS	Data Universal Numbering System
DUNS #	DUNS Number
e-Tag	Electronic Tag
EAF	Equivalent Availability Factor
EAL	Estimated Aggregate Liability
EC	Electric Cooperative
ECEII	ERCOT Critical Energy Infrastructure Information
ECI	Element Competitiveness Index
ECRS	ERCOT Contingency Reserve Service
EDI	Electronic Data Interchange
EEA	Energy Emergency Alert
EFT	Electronic Funds Transfer
ELSE	External Load Serving Entity
EMMS	Energy and Market Management System
EMS	Energy Management System
EPRI	Electric Power Research Institute
EPS	ERCOT-Polled Settlement
ERCOT	Electric Reliability Council of Texas, Inc.
ERCOT Board	The Board of Directors of the Electric Reliability Council of Texas, Inc.
ERS	Emergency Response Service
ESI ID	Electric Service Identifier
ESR	Energy Storage Resource
ESREDP	Energy Storage Resource Energy Deployment Performance
ESS	Energy Storage System
F&A	Finance and Audit
FASD	First Available Switch Date
FCE	Future Credit Exposure
Fed	Federal
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
FFSS	Firm Fuel Supply Service
FFSSR	Firm Fuel Supply Service Resource
FGR	Flowgate Right
FIP	Fuel Index Price
FIS	Full Interconnection Study
FME	Frequency Measurable Event
FOP	Fuel Oil Price
FPA	Federal Power Act
FRC	Frequency Responsive Capacity
FRR	Final RPS Requirement
FRRS	Fast Responding Regulation Service

FRRS-Down	Fast Responding Regulation Down Service
FRRS-Up	Fast Responding Regulation Up Service

[NPRR1013: Delete the acronyms "FRRS"," FRRS-Down", and "FRRS-Up" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

GADS	Generation Availability Data System
GREDP	Generation Resource Energy Deployment Performance
GSU	Generator Step-Up
GTBD	Generation To Be Dispatched
GTC	Generic Transmission Constraint
GTL	Generic Transmission Limit
HASL	High Ancillary Service Limit

[NPRR1013: Delete the acronym "HASL" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

HCAP	High System-Wide Offer Cap
HDL	High Dispatch Limit
HE	Hour Ending
HEL	High Emergency Limit
HIO	High Impact Outage
HITE	High Impact Transmission Element
HRL	High Reasonability Limit
HRUC	Hourly Reliability Unit Commitment
HSL	High Sustained Limit
HWR	High Winter Ratio
Hz	Hertz
IBR	Inverter-Based Resource
ICCP	Inter-Control Center Communications Protocol
IDR	Interval Data Recorder
IE	Interconnecting Entity
IEL	Initial Estimated Liability
IGE	Induction Generator Effects
IHLF	Intra-Hour Load Forecast
IHPPF	Intra-Hour PhotoVoltaic Power Forecast
IHWPF	Intra-Hour Wind Power Forecast
IMM	Independent Market Monitor
IMRE	Independent Market Information System Registered Entity
IOU	Investor Owned Utility

IPM	Independent Power Marketer
IROL	Interconnection Reliability Operating Limit
IRR	Intermittent Renewable Resources

kV	Kilovolt
kVA	Kilovolt-Ampere
kVAr	Kilovolt-Ampere reactive
kVArh	Kilovolt-Ampere reactive hour
kW	Kilowatt
kWh	Kilowatt-Hour

LASL	Low Ancillary Service Limit

[NPRR1013: Delete the acronym "LASL" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

LCAP	Low System-Wide Offer Cap
LDL	Low Dispatch Limit
LEL	Low Emergency Limit
LFC	Load Frequency Control
LMP	Locational Marginal Price
LPC	Low Power Consumption
LRL	Low Reasonability Limit
LRS	Load Ratio Share
LSE	Load Serving Entity
LSL	Low Sustained Limit

MCPC	Market Clearing Price for Capacity
MDAS	Meter Data Acquisition System
MIS	Market Information System
MMBtu	Million British Thermal Units
MOC	Mitigated Offer Cap
MOU	Municipally Owned Utility
MPC	Maximum Power Consumption
MPT	Main Power Transformer
MRA	Must-Run Alternative
MRE	Meter Reading Entity
MTLF	Mid-Term Load Forecast
MVA	Megavolt Ampere
MVAr	Mega Volt-Amperes reactive
MW	Megawatt
MWh	Megawatt Hour

NCBI	Notice of Change of Banking Information
NCI	Notice of Change of Information

NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NFRC	Non-Frequency Responsive Capacity

[NPRR1013: Delete the acronym "NFRC" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

NIST	National Institute of Standards and Technology
NOIE	Non-Opt-In Entity
NOMCR	Network Operations Model Change Request
Non-Spin	Non-Spinning Reserve
NSA	Network Security Analysis
NSO	Notification of Suspension of Operations
NWSIDR	Non-Weather Sensitive IDR
O&M	Operations and Maintenance
OAE	Outage Adjustment Evaluation
OCN	Operating Condition Notice
ORDC	Operating Reserve Demand Curve

[NPRR1013: Delete the acronym "ORDC" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

OSA	Outage Schedule Adjustment
PCAP	Pre-Contingency Action Plan
PCRR	Pre-Assigned Congestion Revenue Right
PMI	Private Microgrid Island
PNM	Peaker Net Margin
POLR	Provider of Last Resort
POC	Peaking Operating Cost
POCC	Point of Common Coupling
POI	Point of Interconnection
POIB	Point of Interconnection Bus
POS	Power Operating System
PRC	Physical Responsive Capability
PRM	Planning Reserve Margin
PRR	Protocol Revision Request
PRS	Protocol Revision Subcommittee
PSS	Power System Stabilizer
PTB	Price-to-Beat
PTP	Point-to-Point
PUCT	Public Utility Commission of Texas

PURA	Public Utility Regulatory Act, Title II, Texas Utility Code
PURPA	Public Utility Regulatory Policy Act
PV	PhotoVoltaic
PVGR	PhotoVoltaic Generation Resource
PVGRPP	PhotoVoltaic Generation Resource Production Potential
PWG	Profiling Working Group
QF	Qualifying Facility
QSE	Qualified Scheduling Entity
QSGR	Quick Start Generation Resource
RAP	Remedial Action Plan
RAS	Remedial Action Scheme
RDF	Reserve Discount Factor
REC	Renewable Energy Credit
Reg-Down	Regulation Down
Reg-Up	Regulation Up
REP	Retail Electric Provider
RID	Resource ID
RIDR	Representative IDR
RMR	Reliability Must-Run
RMS	Retail Market Subcommittee
ROS	Reliability and Operations Subcommittee
RPG	Regional Planning Group
RPP	Renewable Production Potential
RPS	Renewable Portfolio Standard
RRS	Responsive Reserve
RSASM	Reconfiguration Supplemental Ancillary Services Market

[NPRR1013: Delete the acronym "RSASM" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

RTEP	Real-Time Energy Price
RTM	Real-Time Market
RTSWCAP	Real-Time System-Wide Offer Cap
RUC	Reliability Unit Commitment
RUCAC	Reliability Unit Commitment for Additional Capacity
SASM	Supplemental Ancillary Services Market

[NPRR1013: Delete the acronym "SASM" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

SCADA	Supervisory Control and Data Acquisition
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SDRAMP	SCED Down Ramp Rate
SFT	Simultaneous Feasibility Test
SGIA	Standard Generation Interconnection Agreement
SMOG	Settlement Metering Operating Guide
SODESS	Settlement Only Distribution Energy Storage System
SODG	Settlement Only Distribution Generator
SOESS	Settlement Only Energy Storage System
SOG	Settlement Only Generator
SOTESS	Settlement Only Transmission Energy Storage System
SOTG	Settlement Only Transmission Generator
SOTSG	Settlement Only Transmission Self-Generator
SRR	Statewide RPS Requirement
SSCI	Subsynchronous Control Interaction
SSO	Subsynchronous Oscillation
SSR	Subsynchronous Resonance
STEC	South Texas Electric Cooperative
STLF	Short-Term Load Forecast
STPPF	Short-Term PhotoVoltaic Power Forecast
STWPF	Short-Term Wind Power Forecast
SURAMP	SCED Up Ramp Rate
SWCAP	System-Wide Offer Cap

[NPRR1013: Delete the acronym "SWCAP" above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

SWGR	Switchable Generation Resource
T&D	Transmission and Distribution
TAC	Technical Advisory Committee
TDSP	Transmission and/or Distribution Service Provider
TDTWG	Texas Data Transport Working Group
TEPPF	Total ERCOT PhotoVoltaic Power Forecast
TEWPF	Total ERCOT Wind Power Forecast
TIER	Times/Interest Earning Ratio
TGR	Transmission Generation Resource
TLF	Transmission Loss Factor
TMTP	Texas Market Test Plan
TO	Transmission Operator
TOAP	Temporary Outage Action Plan
TOU	Time Of Use
TOUS	Time Of Use Schedule
TPE	Total Potential Exposure

TSP	Transmission Service Provider
TTPT	Texas Test Plan Team
TUO	Total Usable Offset
TWC	Texas Water Code
TX SET	Texas Standard Electronic Transaction
UDSP	Updated Desired Set Point
UFE	Unaccounted For Energy
UFLS	Under-Frequency Load Shed
URL	Unit Reactive Limit
USA	User Security Administrator
USD	United States Dollar or U.S. Dollar
UVLS	Under-Voltage Load Shed
VAr	Volt-Ampere reactive
VDI	Verbal Dispatch Instruction
VEE	Validation, Editing and Estimating
VSS	Voltage Support Service
WAN	Wide Area Network
WGR	Wind-powered Generation Resource
WGRPP	Wind-powered Generation Resource Production Potential
WMS	Wholesale Market Subcommittee
WRUC	Weekly Reliability Unit Commitment
WSIDR	Weather Sensitive IDR
WSL	Wholesale Storage Load
XML	Extensible Markup Language

ERCOT Nodal Protocols

Section 3: Management Activities for the ERCOT System

January 27, 2023

3 MANAGEMENT ACTIVITIES FOR THE ERCOT SYSTEM

(1) This section focuses on the management activities, including Outage Coordination, Resource Adequacy, Load forecasting, transmission operations and planning, and contracts for Ancillary Services for the ERCOT System.

3.1 Outage Coordination

(1) "Outage Coordination" is the management of Transmission Facilities Outages and Resource Outages in the ERCOT System. Facility owners are solely and directly responsible for the performance of all maintenance, repair, and construction work, whether on energized or de-energized facilities, including all activities related to providing a safe working environment.

3.1.1 Role of ERCOT

(1) ERCOT shall coordinate and use reasonable efforts, consistent with Good Utility Practice, to accept, approve or reject all requested Outage plans for maintenance, repair, and construction of both Transmission Facilities and Resources within the ERCOT System. ERCOT may reject an Outage plan under certain circumstances, as set forth in these Protocols.

(2) ERCOT's responsibilities with respect to Outage Coordination include:

(a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) in coordination with and based on information regarding all Entities' Planned Outages and Maintenance Outages;

[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) and Direct Current Tie Operators (DCTOs) in coordination with and based on information regarding all Entities' Planned Outages and Maintenance Outages;

(b) Assessing the adequacy of available Resources, based on planned and known Resource Outages, relative to forecasts of Load, Ancillary Service requirements, and reserve requirements;

(c) Coordinating all Planned Outage and Maintenance Outage plans and approving or rejecting Outage plans for Planned Outages of Resources;

(d) Coordinating and approving or rejecting Outage plans for Planned Outages of Reliability Must-Run (RMR) Units under the terms of the applicable RMR Agreements;

(e) Coordinating and approving or rejecting Outage plans associated with Black Start Resources under the applicable Black Start Unit Agreements;

(f) Coordinating and approving or rejecting Outage plans affecting Subsynchronous Resonance (SSR) vulnerable Generation Resources that do not have SSR Mitigation in the event of five or six concurrent transmission Outages;

(g) Coordinating and approving or rejecting changes to existing Resource Outage plans;

(h) Monitoring how Planned Outage schedules compare with actual Outages;

(i) Posting all proposed and approved schedules for Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities on the Market Information System (MIS) Secure Area under Section 3.1.5.13, Transmission Report;

(j) Creating and posting aggregated MW of Planned Outages for Resources on the MIS Secure Area under Section 3.2.3, Short-Term System Adequacy Reports;

(k) Monitoring Transmission Facilities and Resource Forced Outages and Maintenance Outages of immediate nature and implementing responses to those Outages as provided in these Protocols;

(l) Establishing and implementing communication procedures:

    (i) For a TSP to request approval of Transmission Facilities Planned Outage and Maintenance Outage plans; and

[NPRR857: Replace item (i) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

    (i) For a TSP or a DCTO to request approval of Transmission Facilities Planned Outage and Maintenance Outage plans; and

(ii) For a Resource Entity's designated Single Point of Contact to submit Outage plans and to coordinate Resource Outages;

(m) Establishing and implementing record-keeping procedures for retaining all requested Planned Outages, Maintenance Outages, Rescheduled Outages, and Forced Outages; and

(n) Planning and analyzing Transmission Facilities Outages.

3.1.2 Planned Outage, Maintenance Outage, or Rescheduled Outage Data Reporting

(1) Each Resource Entity shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plans for all Outages. All information submitted about Planned Outages, Maintenance Outages, or Rescheduled Outages must be submitted by the Resource Entity or the TSP under this Section. If an Outage plan for a Resource is also applicable to the Current Operating Plan (COP), the Qualified Scheduling Entity (QSE) responsible for the Resource shall also update the COP to provide the same information describing the Outage. Each TSP shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plan, including, but not limited to, submitting the actual start and end date and time for Planned Outages of Transmission Facilities in the Outage Scheduler by hour ending 0800 of the current Operating Day for all scheduled work completed prior to hour ending 0600 of the current Operating Day.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each Resource Entity shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plans for all Outages. All information submitted about Planned Outages, Maintenance Outages, or Rescheduled Outages must be submitted by the Resource Entity, TSP, or DCTO under this Section. If an Outage plan for a Resource is also applicable to the Current Operating Plan (COP), the Qualified Scheduling Entity (QSE) responsible for the Resource shall also update the COP to provide the same information describing the Outage. Each TSP and DCTO shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage plan, including, but not limited to, submitting the actual start and end date and time for Planned Outages of Transmission Facilities in the Outage Scheduler by hour ending 0800 of the current Operating Day for all scheduled work completed prior to hour ending 0600 of the current Operating Day.

3.1.3 Rolling 12-Month Outage Planning and Update

3.1.3.1 Transmission Facilities

(1) Each TSP shall provide to ERCOT a plan for Planned Outages, Maintenance Outages and Rescheduled Outages in an ERCOT-provided format for the next 12 months updated monthly. Planned Outage, Maintenance Outage, and Rescheduled Outage scheduling data for Transmission Facilities must be kept current. Updates must identify all changes to any previously proposed Planned Outages, Maintenance Outages, or Rescheduled Outages and any additional Planned Outages, Maintenance Outages, or Rescheduled Outages anticipated over the next 12 months. ERCOT shall coordinate in-depth reviews of the 12-month plan with each TSP at least twice per year.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP and DCTO shall provide to ERCOT a plan for Planned Outages, Maintenance Outages, and Rescheduled Outages in an ERCOT-provided format for the next 12 months updated monthly. Planned Outage, Maintenance Outage, and Rescheduled Outage scheduling data for Transmission Facilities must be kept current. Updates must identify all changes to any previously proposed Planned Outages, Maintenance Outages, or Rescheduled Outages and any additional Planned Outages, Maintenance Outages, or Rescheduled Outages anticipated over the next 12 months. ERCOT shall coordinate in-depth reviews of the 12-month plan with each TSP at least twice per year.

3.1.3.2 Resources

(1) Each Resource Entity shall provide to ERCOT a Planned Outage and Maintenance Outage plan for Generation Resources in an ERCOT-provided format for at least the next 12 months updated monthly. Planned Outage and Maintenance Outage plans must be updated as soon as practicable following any change. Updates, through an electronic interface as specified by ERCOT, must identify any changes to previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outages.

(2) ERCOT shall report statistics monthly on how Resource Planned Outages compare with actual Resource Outages, and post those statistics to the MIS Secure Area.

3.1.4 Communications Regarding Resource and Transmission Facilities Outages

3.1.4.1 Single Point of Contact

(1) All communications concerning a Planned Outage, Maintenance Outage, or Rescheduled Outage must be between ERCOT and the designated "Single Point of Contact" for each TSP or Resource Entity. All nonverbal communications concerning Planned Outages or Rescheduled Outages must be conveyed through an electronic interface as specified by ERCOT. The TSP or Resource Entity shall identify, in its initial request or response, the Single Point of Contact, with primary and alternate means of communication. The Resource Entity or TSP shall submit a Notice of Change of Information (NCI) form (Section 23, Form E, Notice of Change of Information) when changes occur to a Single Point of Contact. This identification must be confirmed in all communications with ERCOT regarding Planned Outage, Maintenance Outage, or Rescheduled Outage requests.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) All communications concerning a Planned Outage, Maintenance Outage, or Rescheduled Outage must be between ERCOT and the designated "Single Point of Contact" for each TSP, DCTO, or Resource Entity. All nonverbal communications concerning Planned Outages or Rescheduled Outages must be conveyed through an electronic interface as specified by ERCOT. The TSP, DCTO, or Resource Entity shall identify, in its initial request or response, the Single Point of Contact, with primary and alternate means of communication. The Resource Entity, TSP, or DCTO shall submit a Notice of Change of Information (NCI) form (Section 23, Form E, Notice of Change of Information) when changes occur to a Single Point of Contact. This identification must be confirmed in all communications with ERCOT regarding Planned Outage, Maintenance Outage, or Rescheduled Outage requests.

(2) The Single Point of Contact must be either a person or a position available seven days per week and 24 hours per day for each Resource Entity and TSP. The Resource Entity shall designate its QSE as its Single Point of Contact. The designated Single Point of Contact for a Generation Resource that has been split into two or more Split Generation Resources shall be the Master QSE. The Single Point of Contact for the TSP must be designated under the ERCOT Operating Guides.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) The Single Point of Contact must be either a person or a position available seven days per week and 24 hours per day for each Resource Entity, TSP, or DCTO. The Resource Entity shall designate its QSE as its Single Point of Contact. The designated Single Point of Contact for a Generation Resource that has been split into two or more Split Generation Resources shall be the Master QSE. The Single Point of Contact for each TSP and DCTO must be designated under the ERCOT Operating Guides.

3.1.4.2 Method of Communication

(1) ERCOT, each TSP, and each Resource Entity shall communicate according to ERCOT procedures under these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages must be processed through the ERCOT Outage Scheduler on the ERCOT programmatic interface, except for Forced Outages and Maintenance Level I Outages, which must be communicated to ERCOT immediately via the Current Operating Plan if submitted for a Resource and using the Outage Scheduler if submitted by a TSP. This does not prohibit any verbal communication when the situation warrants it. ERCOT shall develop guidelines for the types of events that may require verbal communication.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT and each TSP, DCTO, and Resource Entity shall communicate according to ERCOT procedures under these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages must be processed through the ERCOT Outage Scheduler on the ERCOT programmatic interface, except for Forced Outages and Maintenance Level I Outages, which must be communicated to ERCOT immediately via the Current Operating Plan if submitted for a Resource and using the Outage Scheduler if submitted by a TSP or DCTO. This does not prohibit any verbal

communication when the situation warrants it. ERCOT shall develop guidelines for the types of events that may require verbal communication.

3.1.4.3 Reporting for Planned Outages, Maintenance Outages, and Rescheduled Outages of Resource and Transmission Facilities

(1) Each Resource Entity and TSP shall submit information regarding proposed Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities or Planned Outages and Maintenance Outages of Generation Resources under procedures adopted by ERCOT. The obligation to submit that information applies to each Resource Entity that is responsible to operate or maintain a Generation Resource that is part of or that affects the ERCOT System. The obligation to submit that information applies to each TSP or Resource Entity that is responsible to operate or maintain Transmission Facilities that are part of or affect the ERCOT System. A Resource Entity or TSP is also obligated to submit information for Transmission Facilities or Generation Resources that are not part of the ERCOT System or that do not affect the ERCOT System if that information is required for regional security coordination as determined by ERCOT.

[NPRR857 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; and upon system implementation for NPRR1014:]

(1) Each Resource Entity, TSP, and DCTO shall submit information regarding proposed Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities or Planned Outages and Maintenance Outages of Generation Resources or Energy Storage Resources (ESRs) under procedures adopted by ERCOT. The obligation to submit that information applies to each Resource Entity that is responsible to operate or maintain a Generation Resource or ESR that is part of or that affects the ERCOT System. The obligation to submit that information applies to each TSP, DCTO, or Resource Entity that is responsible to operate or maintain Transmission Facilities that are part of or affect the ERCOT System. A Resource Entity, TSP, or DCTO is also obligated to submit information for Transmission Facilities or Generation Resources or ESRs that are not part of the ERCOT System or that do not affect the ERCOT System if that information is required for regional security coordination as determined by ERCOT.

(2) Before taking an RMR or Black Start Resource ("Reliability Resources") out of service for a Planned Outage or Maintenance Outage, the Single Point of Contact for that Reliability Resource must obtain ERCOT's approval of the schedule of the Planned Outage or Maintenance Outage. ERCOT shall review and approve or reject each

proposed Planned Outage or Maintenance Outage Schedule under this Section and the applicable Agreements.

(3) A Firm Fuel Supply Service Resource (FFSSR) shall not schedule or request a Planned Outage that would occur during the period of December 1 through March 1.

3.1.4.4 Management of Forced Outages or Maintenance Outages

(1) In the event of a Forced Outage, the Resource Entity or QSE, as appropriate, or TSP must notify ERCOT as soon as practicable by:

[NPRR857 and NPRR1085: Replace applicable portions of paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; or upon system implementation for NPRR1085:]

(1) In the event of a Forced Outage, after the affected equipment is removed from service, the Resource Entity or QSE, as appropriate, TSP, or DCTO must notify ERCOT of its action by:

(a) For Resource Outages:

(i) Changing the telemetered Resource Status, including a text description when it becomes known, of the cause of the Forced Outage;

(ii) Updating the COP; and

(iii) Updating the Outage Scheduler.

[NPRR1085: Replace paragraph (a) above with the following upon system implementation:]

(a) For Resource Outages:

(i) Changing the telemetered Resource Status to the appropriate Off-Line status as soon as practicable but no longer than 15 minutes after the Forced Outage occurs;

(ii) Updating the COP as soon as practicable but no longer than 60 minutes after the Forced Outage occurs; and

(iii) Updating the Outage Scheduler, if necessary.

(b) For Transmission Facilities Forced Outages:

(i) Changing the telemetered status of the affected Transmission Elements; and

(ii) Updating the Outage Scheduler with the expected return-to-service time.

[NPRR1085: Insert paragraph (c) below upon system implementation:]

(c) Each TSP and QSE shall timely update telemetry, COP status, and/or the Outage Scheduler, as applicable, in accordance with paragraphs (a) and (b) above unless in the reasonable judgment of the TSP or QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The TSP or QSE is excused from updating the telemetered status, COP, and/or Outage Scheduler only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the telemetered status, COP, and/or Outage Scheduler begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

(2) Forced Outages may require ERCOT to review and withdraw approval of previously approved or accepted, as applicable, Planned Outage, Maintenance Outage, or Rescheduled Outage schedules to ensure reliability.

(3) For Maintenance Outages, the Resource Entity or QSE, as appropriate, or TSP shall notify ERCOT of any Resource or Transmission Facilities Maintenance Outage according to the Maintenance Outage Levels by updating the COP and Outage Scheduler. ERCOT shall coordinate the removal of facilities from service within the defined timeframes as specified by the TSP, QSE or Resource Entity in its notice to ERCOT.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) For Maintenance Outages, the Resource Entity or QSE, as appropriate, TSP, or DCTO shall notify ERCOT of any Resource or Transmission Facilities Maintenance Outage according to the Maintenance Outage Levels by updating the COP and Outage Scheduler. ERCOT shall coordinate the removal of facilities from service within the defined timeframes as specified by the TSP, DCTO, QSE, or Resource Entity in its notice to ERCOT.

(4) ERCOT may require supporting information describing Forced Outages and Maintenance Outages. ERCOT may reconsider and withdraw approvals of other previously approved Transmission Facilities Outage or an Outage of a Reliability Resource as a result of Forced Outages or Maintenance Outages, if necessary, in ERCOT's determination to protect system reliability. When ERCOT approves a Maintenance Outage, ERCOT shall coordinate timing of the appropriate course of action under these Protocols.

(5) Removal of a Resource or Transmission Facilities from service under Maintenance Outages must be coordinated with ERCOT. To minimize harmful impacts to the system in urgent situations, the equipment may be removed immediately from service, provided notice is given immediately, by the Resource Entity or TSP, to ERCOT of such action.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) Removal of a Resource or Transmission Facilities from service under Maintenance Outages must be coordinated with ERCOT. To minimize harmful impacts to the system in urgent situations, the equipment may be removed immediately from service, provided the Resource Entity, TSP, or DCTO immediately gives notice of such action to ERCOT.

3.1.4.5 Notice of Forced Outage or Unavoidable Extension of Planned, Maintenance, or Rescheduled Outage Due to Unforeseen Events

(1) If a Planned, Maintenance, or Rescheduled Outage is not completed within the ERCOT-approved timeframe and the Transmission Facilities or Resources are in such a condition that they cannot be restored at the Outage schedule completion date, the requesting party shall submit to ERCOT a Forced Outage (unavoidable extension) form describing the extension of the Outage and providing a revised return date.

(2) Any transmission Forced Outage that occurs in Real-Time and that is expected to continue for longer than two hours must be entered into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Outage. Any transmission Forced Outage with a duration exceeding two hours must be entered into the Outage Scheduler as soon as practicable but no longer than 150 minutes after the beginning of the transmission Forced Outage, if not already reported in the Outage Scheduler.

(3) Any Resource Forced Outage that occurs in Real-Time must be entered into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Forced Outage.

(4) If the QSE is to receive the exemption described in paragraph (6)(d) of Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance, the QSE will notify ERCOT Operators by voice communication of every Forced Outage, Forced Derate, or Startup Loading Failure within 15 minutes.

(5) For a Startup Loading Failure, the Resource Entity or its designee must enter a Forced Outage in the Outage Scheduler if the Resource was in an Off-Line status prior to the Startup Loading Failure or update the existing Outage for the Resource if the Resource was on Outage prior to the Startup Loading Failure. The Resource Entity or its designee must also provide a text entry in the supporting information field of the Outage Scheduler that includes the following:

(a) A statement that a Startup Loading Failure occurred;

(b) An explanation of the cause of the Startup Loading Failure using the best available information at the time the Outage or update to the existing Outage is entered, which must be updated if more accurate information becomes available; and

(c) The start time and end time of the Startup Loading Failure portion of the Outage. Multiple consecutive startup attempts may be aggregated into a single Startup Loading Failure event with a single start and end time.

3.1.4.6 Outage Coordination of Potential Transmission Emergency Conditions

(1) If ERCOT forecasts an inability to meet applicable transmission reliability standards, has exercised all other reasonable options, and there is only one QSE with approved or accepted Resource Outages which could resolve the situation if the start of one or more of the Resource Outages at a single Resource site were delayed or one or more ongoing Resource Outages at a single Resource site were restored early, then ERCOT may contact that QSE and attempt to reach a mutually acceptable solution to delay or reschedule one or more of those Outages. In this case, ERCOT is not obligated to follow the process described in Section 3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities. ERCOT shall not provide information to the QSE during these contacts which is not directly related to the QSE's Planned Resource Outage(s) and is not otherwise available to all other Market Participants.

(2) If ERCOT and the QSE are unable to reach a mutually agreeable solution to change the Resource Outage, ERCOT may issue an Outage Schedule Adjustment (OSA) to the QSE for the Resource.

[NPRR930: Insert paragraph (3) below upon system implementation and renumber accordingly:]

(3) If there are Resources at multiple sites with approved or accepted Resource Outages, whose approval or acceptance could be withdrawn to meet the applicable transmission reliability standards, ERCOT shall utilize the process described in Section 3.1.6.9.

(3) This Section is not intended to restrict ongoing Outage Coordination activities occurring more than seven days in advance of Real-Time.

3.1.4.7 Reporting of Forced Derates

(1) If a Generation Resource experiences a Forced Derate in an amount greater than ten MW, and 5% of its Seasonal net maximum sustainable rating, and the Forced Derate lasts longer than 30 minutes, the Resource Entity or its designee must enter the Forced Derate into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Forced Derate.

(2) If a Forced Derate that has already been reported changes by an amount greater than ten MW and 5% of the Generation Resource's Seasonal net maximum sustainable rating, and the change lasts longer than 30 minutes, the Resource Entity or its designee must enter the change as a new Forced Derate into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the change.

(3) Notwithstanding paragraphs (1) and (2) above, for any Forced Derate or change to a Forced Derate that meets the reporting criteria specified in paragraph (1) or (2) above and that is caused by ambient temperature or humidity, the Resource Entity or its designee must enter the Forced Derate into the Outage Scheduler as soon as practicable but no longer than eight hours after the beginning of the Force Derate or change.

[NPRR1085: Insert paragraphs (4)-(6) below upon system implementation:]

(4) The QSE must appropriately update the telemetered High Sustained Limit (HSL) and any applicable telemetry as specified in paragraph (2) of Section 6.5.5.2, Operational Data Requirements, based on the Forced Derate, as soon as practicable but no longer than 15 minutes after the beginning of a Forced Derate, if the Forced Derate is greater than ten MW and more than 5% of the Seasonal net maximum sustainable rating of the Resource and its expected or actual duration is greater than 30 minutes. Alternatively for a Forced Derate, a QSE may use the ONHOLD process described in paragraph (2) of Section 6.5.5.1, Changes in Resource Status.

(5) The QSE must update the COP as soon as practicable but no longer than 60 minutes after the beginning of a Forced Derate, if the Forced Derate is greater than 20 MW and its expected duration is greater than 120 minutes.

(6) Each QSE shall timely update the telemetered HSL and COP unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating

the telemetered HSL and/or COP only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the telemetered HSL and/or COP begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

3.1.4.8 Resource Forced Outage Report

(1) Three days after each Operating Day, ERCOT shall post to the ERCOT website a report that identifies each Forced Outage, Maintenance Outage, or Forced Derate of a Generation Resource or Energy Storage Resource (ESR) that occurs during, or that extends into, that Operating Day. At a minimum, the report shall contain:

(a) The Resource name;

(b) The Resource unit code;

(c) The Resource's fuel type;

(d) The type of Outage or derate;

(e) The Resource's applicable Seasonal net maximum sustainable rating;

(f) The available MW during the Outage or derate;

(g) The effective MW reduction due to the Outage or derate;

(h) The start date/time and the planned or actual end date/time; and

(i) The entry in the "nature of work" field in the Outage Scheduler for each Outage or derate.

3.1.5 Transmission System Outages

3.1.5.1 ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities

(1) A TSP or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP requests, the TSPs shall enter such requests in the Outage Scheduler. For Resource Entity requests, the Resource Entity shall enter such requests in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP enters the breaker and switch

statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP or Resource Entity in accordance with this Section constitutes a request for ERCOT's approval of the Outage Schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) A TSP, DCTO, or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP, DCTO, and Resource Entity requests, the requesting Entity shall enter such a request in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP or DCTO enters the breaker and switch statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP, DCTO, or Resource Entity in accordance with this Section constitutes a request for ERCOT's approval of the Outage Schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP, DCTO, or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests.

(2) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules. ERCOT shall transmit its approvals and rejections to TSPs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of

Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules. ERCOT shall transmit its approvals and rejections to TSPs and DCTOs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities.

(3) Private Use Network Outage requests submitted pursuant to this Section shall not be publicly posted.

(4) To the extent authorized by its tariff, an External Load Serving Entity (ELSE) or Non-Opt-In Entity (NOIE) that provides retail service to a Resource Entity that owns or operates a Generation Resource may request that the TSP to which the Generation Resource is interconnected disconnect the Generation Resource due to the Resource Entity’s failure to comply with the payment requirements in the ELSE’s or NOIE’s retail tariff.

(5) Within five Business Days after receiving a request from a Load Serving Entity (LSE) to disconnect a Generation Resource due to the Resource Entity’s failure to comply with LSE’s payment requirements, including a request received pursuant to paragraph (4) above, the interconnecting TSP shall enter a request in the Outage Scheduler for an Outage of any Transmission Facilities interconnecting the Generation Resource to the ERCOT System. Any Outage requested or taken pursuant to this Section shall be treated as a Planned Outage for all purposes under the Protocols. For any such Outage request, the requesting TSP shall enter a start date that it is at least four days after the date the request is submitted in the Outage Scheduler and shall enter an Outage end date that is 14 days from the date of the requested start date. Unless storm or system reliability issues prevent immediate dispatch of personnel, for any LSE request to reconnect a Customer that was disconnected pursuant to this section, the interconnecting TSP shall end the Outage and reconnect the Generation Resource the same Business Day if the request is received by 1200, or the next Business Day if the request is received after 1200. If a reconnect request is not received within four days of the Outage end date, the interconnecting TSP shall enter another request in the Outage Scheduler for an Outage of any Transmission Facilities interconnecting the Generation Resource to the ERCOT System with an Outage end date 14 days beyond the prior Outage end date. At any time,

ERCOT may withdraw approval of the Outage and instruct the TSP to reconnect the Generation Resource if it deems cancellation necessary to address reliability concerns.

3.1.5.2 Receipt of TSP Requests by ERCOT

(1) ERCOT shall acknowledge each request for approval of a Transmission Planned Outage or Maintenance Outage schedule within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the TSP regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Transmission Facilities.

[NPRR857: Replace Section 3.1.5.2 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

3.1.5.2 Receipt of TSP and DCTO Requests by ERCOT

(1) ERCOT shall acknowledge each request for approval of a Transmission Planned Outage or Maintenance Outage schedule within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the TSP or DCTO regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Transmission Facilities.

3.1.5.3 Timelines for Response by ERCOT for TSP Requests

(1) For Transmission Facilities Outages, ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between the request for approval of the proposed Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
Three days	1800 hours, two days before the start of the proposed Outage
Between four and eight days	1800 hours, three days before the start of the proposed Outage
Between nine days and 45 days	Four days before the start of the proposed Outage
Between 46 and 90 days	30 days before the start of the proposed Outage
Greater than 90 days	75 days before the start of the proposed Outage

(2) For Outages scheduled at least three days before the scheduled start date of the proposed Outage, ERCOT shall make reasonable attempts to accommodate unusual circumstances that support TSP requests for approval earlier than required by the schedule above.

(3) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of the approval with the requesting TSP and make reasonable attempts to mitigate the effect of the delay on the TSP.

(4) When ERCOT rejects a request for an Outage, ERCOT shall provide the TSP, in written or electronic form, suggested amendments to the schedules of a Planned Outage or Maintenance Outage of Transmission Facilities. Any such suggested amendments accepted by the TSP must be processed by ERCOT as a Planned Outage or Maintenance Outage of Transmission Facilities request under this Section.

[NPRR857: Replace Section 3.1.5.3 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

3.1.5.3 Timelines for Response by ERCOT for TSP and DCTO Requests

(1) For Transmission Facilities Outages, ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between the request for approval of the proposed Outage and the scheduled start date of the proposed Outage:	ERCOT shall approve or reject no later than:
Three days	1800 hours, two days before the start of the proposed Outage
Between four and eight days	1800 hours, three days before the start of the proposed Outage
Between nine days and 45 days	Four days before the start of the proposed Outage
Between 46 and 90 days	30 days before the start of the proposed Outage
Greater than 90 days	75 days before the start of the proposed Outage

(2) For Outages scheduled at least three days before the scheduled start date of the proposed Outage, ERCOT shall make reasonable attempts to accommodate unusual circumstances that support TSP and DCTO requests for approval earlier than required by the schedule above.

(3) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of the approval with the requesting TSP or

DCTO and make reasonable attempts to mitigate the effect of the delay on the TSP or DCTO.

(4) When ERCOT rejects a request for an Outage, ERCOT shall provide the TSP or DCTO, in written or electronic form, suggested amendments to the schedules of a Planned Outage or Maintenance Outage of Transmission Facilities. Any such suggested amendments accepted by the TSP or DCTO must be processed by ERCOT as a Planned Outage or Maintenance Outage of Transmission Facilities request under this Section.

3.1.5.4 Delay

(1) ERCOT may delay its approval or rejection of a proposed Planned Outage or Maintenance Outage of a Transmission Facilities schedule if the requesting TSP has not submitted sufficient or complete information within the time frames set forth in these Protocols.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT may delay its approval or rejection of a proposed Planned Outage or Maintenance Outage of a Transmission Facilities schedule if the requesting TSP or DCTO has not submitted sufficient or complete information within the time frames set forth in these Protocols.

3.1.5.5 Opportunity Outage of Transmission Facilities

(1) Opportunity Outages of Transmission Facilities may be approved under Section 3.1.6.10, Opportunity Outage.

3.1.5.6 Rejection Notice

(1) If ERCOT rejects a request, ERCOT shall provide the TSP a written or electronic rejection notice that includes:

(a) Specific concerns causing the rejection;

(b) Possible remedies or transmission schedule revisions, if any that might mitigate the basis for rejection; and

(c) An electronic copy of the ERCOT study case for review by the TSP.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) If ERCOT rejects a request, ERCOT shall provide the TSP or DCTO a written or electronic rejection notice that includes:

(a) Specific concerns causing the rejection;

(b) Possible remedies or transmission schedule revisions, if any that might mitigate the basis for rejection; and

(c) An electronic copy of the ERCOT study case for review by the TSP or DCTO.

(2) ERCOT may reject a Planned Outage or Maintenance Outage of Transmission Facilities only:

(a) To protect system reliability or security;

(b) Due to insufficient information regarding the Outage; or

(c) Due to failure to comply with submittal process requirements, as specified in these Protocols.

(3) When multiple proposed Planned Outages, Maintenance Outages, or Rescheduled Outages cause a reliability or security concern, ERCOT shall:

(a) Communicate with each TSP to see if the TSP will adjust its proposed Planned Outage, Maintenance Outage, or Rescheduled Outage schedule;

(b) Determine if each TSP will agree to an alternative Outage schedule; or

(c) Reject, in ERCOT's sole discretion, one or more proposed Outages, considering order of receipt and impact on the ERCOT Transmission Grid.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) When multiple proposed Planned Outages, Maintenance Outages, or Rescheduled Outages cause a reliability or security concern, ERCOT shall:

(a) Communicate with each TSP and DCTO to see if the TSP or DCTO will adjust its proposed Planned Outage, Maintenance Outage, or Rescheduled Outage schedule;

(b) Determine if each TSP or DCTO will agree to an alternative Outage schedule; or

(c) Reject, in ERCOT's sole discretion, one or more proposed Outages, considering order of receipt and impact on the ERCOT Transmission Grid.

3.1.5.7 Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities

(1) If ERCOT believes it cannot meet the applicable reliability standards and has exercised reasonable options, ERCOT may contact the TSP for more information prior to its withdrawal of the approval for a Planned Outage, Maintenance Outage, or Rescheduled Outage. ERCOT shall inform the affected TSP both orally and in written or electronic form as soon as ERCOT identifies a situation that may lead to the withdrawal of ERCOT's approval. If ERCOT withdraws its approval, the TSP may submit a new request for approval of the Planned Outage or Maintenance Outage schedule provided the new request meets the submittal requirements for Outage Scheduling.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) If ERCOT believes it cannot meet the applicable reliability standards and has exercised reasonable options, ERCOT may contact the TSP or DCTO for more information prior to its withdrawal of the approval for a Planned Outage, Maintenance Outage, or Rescheduled Outage. ERCOT shall inform the affected TSP or DCTO both orally and in written or electronic form as soon as ERCOT identifies a situation that may lead to the withdrawal of ERCOT's approval. If ERCOT withdraws its approval, the TSP or DCTO may submit a new request for approval of the Planned Outage or Maintenance Outage schedule provided the new request meets the submittal requirements for Outage Scheduling.

(2) In determining whether to withdraw approval, ERCOT shall duly consider whether the Planned Outage, Maintenance Outage, or Rescheduled Outage affects public infrastructure if ERCOT is made aware of such potential impacts by the TSP (e.g., impacts on highways, ports, municipalities, and counties).

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) In determining whether to withdraw approval, ERCOT shall duly consider whether the Planned Outage, Maintenance Outage, or Rescheduled Outage affects public infrastructure if ERCOT is made aware of such potential impacts by the TSP or DCTO (e.g., impacts on highways, ports, municipalities, and counties).

(3) Prior to withdrawing the approval of a High Impact Outage (HIO) submitted with greater than 90-days' notice, ERCOT shall coordinate with the TSP and may convert the Planned Outage to a Rescheduled Outage. The Rescheduled Outage shall retain the same priority as the original Planned Outage. ERCOT shall attempt to keep the Outage within the same calendar month.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) Prior to withdrawing the approval of a High Impact Outage (HIO) submitted with greater than 90-days' notice, ERCOT shall coordinate with the TSP or DCTO and may convert the Planned Outage to a Rescheduled Outage. The Rescheduled Outage shall retain the same priority as the original Planned Outage. ERCOT shall attempt to keep the Outage within the same calendar month.

3.1.5.8 Priority of Approved Planned, Maintenance, and Rescheduled Outages

(1) In considering TSP requests, ERCOT shall give priority to Planned Outages, Maintenance Outages, and Rescheduled Outages in the order of receipt.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) In considering TSP or DCTO requests, ERCOT shall give priority to Planned Outages, Maintenance Outages, and Rescheduled Outages in the order of receipt.

3.1.5.9 Information for Inclusion in Transmission Facilities Outage Requests

(1) Transmission Facilities Outage requests submitted by a TSP must include the following Transmission Facilities-specific information:

(a) The identity of the Transmission Facilities, in the Network Operations Model, including TSP and location;

(b) The nature of the work, by predefined classifications, to be performed during the proposed Transmission Facilities Outage;

(c) The preferred start and finish dates for the proposed Transmission Planned or Maintenance Outage;

(d) The time required to: (i) finish the Transmission Planned Outage or Maintenance Outage and (ii) restore the Transmission Facilities to normal operation;

(e) Primary and alternate telephone numbers for the TSP's Single Point of Contact, as described in Section 3.1.4.1, Single Point of Contact, and the name of the individual submitting the information;

(f) The scheduling flexibility (i.e., the earliest start date and the latest finish date for the Outage);

(g) Any Transmission Facilities that must be out of service to facilitate the TSP's request;

(h) Any remedial actions or special protection systems necessary during the Outage and the contingency that would require the remedial action or relay action; and

(i) Any other relevant information related to the proposed Outage or any unusual risks affecting the schedule.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Transmission Facilities Outage requests submitted by a TSP or a DCTO must include the following Transmission Facilities-specific information:

(a) The identity of the Transmission Facilities, in the Network Operations Model, including TSP or DCTO and location;

(b) The nature of the work, by predefined classifications, to be performed during the proposed Transmission Facilities Outage;

(c) The preferred start and finish dates for the proposed Transmission Planned or Maintenance Outage;

(d) The time required to: (i) finish the Transmission Planned Outage or Maintenance Outage and (ii) restore the Transmission Facilities to normal operation;

(e) Primary and alternate telephone numbers for the TSP's or DCTO's Single Point of Contact, as described in Section 3.1.4.1, Single Point of Contact, and the name of the individual submitting the information;

(f) The scheduling flexibility (i.e., the earliest start date and the latest finish date for the Outage);

(g) Any Transmission Facilities that must be out of service to facilitate the TSP's or DCTO's request;

(h) Any remedial actions or special protection systems necessary during the Outage and the contingency that would require the remedial action or relay action; and

(i) Any other relevant information related to the proposed Outage or any unusual risks affecting the schedule.

3.1.5.10 Additional Information Requests

(1) The requesting TSP shall comply with any ERCOT requests for more information about, or for clarification of, the information submitted by the TSP for a proposed Outage.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) The requesting TSP or DCTO shall comply with any ERCOT requests for more information about, or for clarification of, the information submitted by the TSP or DCTO for a proposed Outage.

3.1.5.11 Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests

(1) ERCOT shall evaluate requests, approve, or reject Transmission Facilities Planned Outages and Maintenance Outages according to the requirements of this section. ERCOT may approve Outage requests provided the Outage in combination with other proposed Outages does not cause a violation of applicable reliability standards. ERCOT shall reject Outage requests that do not meet the submittal timeline specified in Section 3.1.5.12, Submittal Timeline for Transmission Facility Outage Requests. ERCOT shall consider the following factors in its evaluation:

(a) Forecasted conditions during the time of the Outage;

(b) Outage plans submitted by Resource Entities and TSPs under Section 3.1, Outage Coordination;

[NPRR857: Replace item (b) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(b) Outage plans submitted by Resource Entities, TSPs, and DCTOs under Section 3.1, Outage Coordination;

(c) Forced Outages of Transmission Facilities;

(d) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software;

(e) Potential for the proposed Outages to cause SSR vulnerability to Generation Resources that do not have SSR Mitigation in the event of five or six concurrent transmission Outages;

(f) Previously approved Planned Outages, Maintenance Outages, and Rescheduled Outages;

(g) Impacts on the transfer capability of Direct Current Ties (DC Ties); and

(h) Good Utility Practice for Transmission Facilities maintenance.

(2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

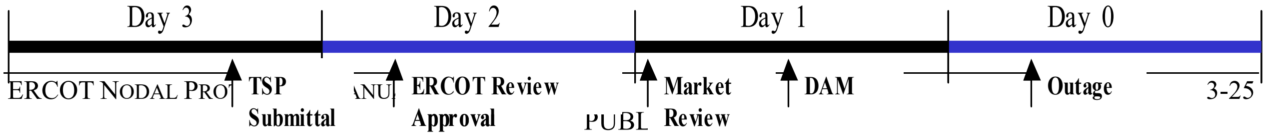
(2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP or DCTO.

(3) When ERCOT identifies that an HIO has been submitted with 90-days or less notice, ERCOT may coordinate with TSP to make reasonable efforts to minimize the impact.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) When ERCOT identifies that an HIO has been submitted with 90-days or less notice, ERCOT may coordinate with the TSP or DCTO to make reasonable efforts to minimize the impact.

3.1.5.12 Submittal Timeline for Transmission Facility Outage Requests



(1) TSPs shall submit all requests for Planned Outages and Maintenance Outages or changes to existing approved Outages of Transmission Elements in the Network Operations Model to ERCOT no later than the minimum amount of time between the submittal of a request to ERCOT for approval of a proposed Outage and the scheduled start date of the proposed Outage, according to the following table:

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) TSPs and DCTOs shall submit all requests for Planned Outages and Maintenance Outages or changes to existing approved Outages of Transmission Elements in the Network Operations Model to ERCOT no later than the minimum amount of time between the submittal of a request to ERCOT for approval of a proposed Outage and the scheduled start date of the proposed Outage, according to the following table:

Type of Outage	**Minimum amount of time between the Outage request and the scheduled start date of the proposed Outage:**	**Minimum amount of time between any change to an Outage request and the scheduled end date an existing Outage:**
Forced Outage	Immediate	Immediate
Maintenance Outage Level I	Immediate	Immediate
Maintenance Outage Level II	Two days [1]	Two days [1]
Maintenance Outage Level III	Three days	Three days
Planned Outage	Three days	Three days
Simple Transmission Outage	One day	One day

Note:

1. For reliability purposes, ERCOT may reduce to one day on a case-by-case basis.

3.1.5.13 Transmission Report

(1) ERCOT shall post on the MIS Secure Area:

(a) Within one hour of receipt by ERCOT, all Transmission Facilities Outages that have been submitted into the ERCOT Outage Scheduler, excluding Private Use Network transmission Outages;

(b) Within one hour of a change of an Outage, all Transmission Facilities Outages, excluding Private Use Network transmission Outages;

(c) Once each day, Outage Scheduler notes related to the coordination of Outages;

(d) At least annually, an updated list of High Impact Transmission Elements (HITEs) pursuant to Section 3.1.8, High Impact Transmission Element (HITE) Identification; and

(e) Once each day, list of HIOs submitted with 90-days or less notice that are accepted or approved.

3.1.6 Outages of Resources Other than Reliability Resources

(1) Resource Entities should submit a request for a Resource Planned Outage as far in advance of the planned start of the Outage as is practicable but no more than 60 months in advance.

(2) ERCOT shall approve or reject all requested Outage plans for a Resource other than a Reliability Resource submitted to ERCOT more than 45 days before the proposed start date of the Outage.

(a) ERCOT shall approve a requested Outage plan for a Resource other than a Reliability Resource if the proposed approval would not cause the aggregate MW of Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity at any point during the duration of the proposed Resource Outage, taking into consideration all previously approved Resource Outages.

(3) If a Resource Entity plans to start a Planned or Maintenance Outage within 45 days, and the Resource Entity has not previously submitted a Resource Outage plan for the Outage, then the Resource Entity must immediately notify ERCOT and include in its notice whether the Outage is a Maintenance (Level I, II, or III) Outage or Planned Outage. ERCOT's response to this notification must comply with these requirements:

(a) ERCOT shall accept Levels I, II, and III Maintenance Outage plans, and ERCOT shall coordinate the Outages within the time frames specified in these Protocols.

(b) ERCOT shall approve Planned Outage plans, except that:

(i) ERCOT shall reject an Outage plan if the proposed Outage would cause the aggregate MW of Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity at any point during the duration of the proposed Outage; and

(ii) ERCOT shall reject an Outage plan if it will impair ERCOT's ability to meet applicable reliability standards, taking into consideration all previously approved and accepted Outages, and other solutions cannot be exercised.

(4) The Resource Entity shall not begin a Planned Outage unless it has received approval of its proposed Outage plan.

(5) ERCOT shall accept Forced Outage plans.

(6) Notwithstanding any other provision of this Section, ERCOT shall approve a requested Outage plan for a nuclear Generation Resource.

(7) Notwithstanding any other provision in this Section, ERCOT shall approve an Outage plan for a Generation Resource that is part of an industrial generation facility if the plan states that the Generation Resource is part of an industrial generation facility, as described in subsection (*l*) of the Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2007), and that the Outage is necessitated by the operational needs of an industrial Load normally served by the Generation Resource, except that ERCOT is not required to approve the Outage plan if ERCOT determines the Outage will impair ERCOT's ability to ensure transmission security.

3.1.6.1 Receipt of Resource Requests by ERCOT

(1) ERCOT shall acknowledge each request for approval of a Resource Planned Outage plan within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the Resource Entity regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Resource Facilities.

3.1.6.2 Resource Outage Plan

(1) Resource Outage plans shall include the following information:

(a) The primary and alternate phone number of the Resource Entity's Single Point of Contact for Outage Coordination;

(b) The Resource identified by the name in the Network Operations Model;

(c) The net megawatts of capacity the Resource Entity anticipates will be available during the Outage (if any);

(d) The estimated start and finish dates for each Planned and Maintenance Outage;

(e) An estimate of the acceptable deviation in the Outage schedule (i.e., the earliest start date and the latest finish date for the Outage); and

(f) The nature of work to be performed during the Outage. For a Forced Outage or Forced Derate, the “nature of work” field in the Outage Scheduler shall indicate the best available information about the cause of the Forced Outage or Forced Derate at the time the Outage or derate is entered and shall be updated as soon as more accurate information becomes available.

(2) When ERCOT accepts a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action within the Resource-specified timeframe. The QSE shall notify ERCOT of the Outage and coordinate the time.

3.1.6.3 Additional Information Requests

(1) ERCOT may request additional information from a Resource Entity regarding the information submitted as part of a Resource Outage plan. ERCOT may not unnecessarily delay requests for information in terms of the required response time.

3.1.6.4 Approval of Changes to a Resource Outage Plan

(1) A Resource Entity should request approval as soon as practicable from ERCOT for all changes to a previously approved Resource Outage plan.

(2) A Resource Entity must request approval from ERCOT for all changes to a previously approved Resource Planned Outage.

(a) ERCOT shall approve requests for changes to Resource Planned Outages and Maintenance Outages, except that:

(i) ERCOT shall reject a Resource Outage plan change request if the proposed approval would cause the aggregate MW of Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity at any point during the duration of the proposed Resource Outage; and

(ii) ERCOT shall reject a Resource Outage plan change request if the proposed approval will impair ERCOT’s ability to meet applicable reliability standards, taking into consideration all previously approved and accepted Outages.

(3) Following approval, where ERCOT determines that the Resource Outage plan is expected to result in a violation of an ERCOT reliability criterion or that may result in a cancellation of a Transmission Facilities Planned Outage, ERCOT may discuss such concerns with the Resource Entity or QSE in an attempt to reach a mutually agreeable resolution, including rescheduling the Outage in a manner agreeable to the Resource Entity. If the Transmission Facilities Planned Outage was submitted after the approval of the Resource Planned Outage, the Resource Entity is not required to reschedule the Resource Outage.

(4) When the scheduled work is complete, any Resource may return from a Planned Outage in accordance with Section 3.1.6.11, Outage Returning Early. ERCOT shall accept this change and, in the event that a Transmission Facilities Outage was scheduled concurrently with the affected Resource(s) Outage, ERCOT shall coordinate between the TSP and the Resource Entity to schedule a time mutually agreeable to both parties for the Resource to be On-Line. If mutual agreement cannot be reached, then ERCOT shall decide, considering expected impact on ERCOT System security, future Outage plans, and participants.

3.1.6.5 Evaluation of Proposed Resource Outage

(1) If a proposed Resource Outage, in conjunction with previously accepted Outages, would cause a violation of applicable reliability standards, ERCOT shall:

  (a) Communicate with the requesting QSE as required under Section 3.1.6.8, Resource Outage Rejection Notice;

  (b) Investigate possible Constraint Management Plans (CMPs) to resolve security violations, based upon security and reliability analysis results and strive to maximize transmission usage consistent with reliable operation; and

  (c) Consider modifying the previous acceptance or approval of one or more Transmission Facilities or reliability Resource Outages, considering order of receipt and impact to the ERCOT System.

(2) If transmission security can be maintained using an alternative considered in items (1)(b) and (1)(c) above, then ERCOT may, in its judgment, direct the selected alternatives and approve the proposed Resource Outage.

(3) If ERCOT does not resolve transmission security issues by using the alternatives considered in items (1)(b) and (1)(c) above, then ERCOT shall reject the proposed Resource Outage.

3.1.6.6 Timelines for Response by ERCOT for Resource Planned Outages

(1) ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between a request for approval of a Planned Outage and the scheduled start of the proposed Outage:	**Maximum duration of a Planned Outage that may be approved with this lead time:**	**ERCOT shall approve or reject no later than:**
Three days	Seven days	ERCOT shall approve or reject by 1800 hours, two days before the start of the proposed Outage
Between four and eight days	Seven days	ERCOT shall approve or reject by 1800 hours, three days prior to the start of the proposed Outage

Between nine and 15 days	15 days	ERCOT shall approve or reject four days before the start of the requested Outage
Between 16 and 45 days	180 days	ERCOT shall approve or reject within five Business Days after submission
Greater than 45 days but less than 60 months	180 days	ERCOT shall approve or reject within five Business Days after submission
Greater than 60 months	180 days	ERCOT shall approve or reject within five Business Days once the Outage start dates are within the 60-month window

(2) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of decision with the QSE and make reasonable attempts to mitigate the effect of the delay. Furthermore, in its sole discretion, ERCOT may approve Planned Outage durations that exceed the maximum durations prescribed in the table above.

(3) The maximum duration of Planned Outages does not apply for Resource Outages under a Notification of Suspension of Operations (NSO) pursuant to Section 3.14.1.1, Notification of Suspension of Operations.

3.1.6.7 Delay

(1) ERCOT may delay its approval or rejection of a proposed Planned Outage plan if the requesting Resource Entity has not submitted sufficient or complete information within the time frames set forth in this Section 3.1.6, Outages of Resources Other than Reliability Resources. Review periods for Planned Outage consideration do not commence until sufficient and complete information is submitted to ERCOT as described in Section 3.1.6.2, Resource Outage Plan.

3.1.6.8 Resource Outage Rejection Notice

(1) If ERCOT rejects a request for a Planned Outage, ERCOT shall provide the QSE a written or electronic rejection notice that includes:

(a) Specific reasons causing the rejection; or

(b) Possible remedies or Resource schedule revisions, if any, that might mitigate the basis for rejection.

(2) ERCOT may reject a Planned Outage of Resource facilities only:

(a) To protect the reliability or security of the ERCOT System;

(b) Due to insufficient information regarding the Outage;

(c) Due to failure to comply with submittal process requirements, as specified in these Protocols;

(d) To stay within the Maximum Daily Resource Planned Outage Capacity; or

(e) As specified elsewhere in these Protocols.

(3) When multiple proposed Planned Outages or Maintenance Outages cause a known capacity conflict, ERCOT shall:

(a) Communicate with each QSE to see if the QSE will adjust its proposed Planned Outage schedule;

(b) Determine if each QSE will agree to an alternative Outage schedule; or

(c) Reject, in ERCOT's sole discretion, one or more proposed Outages, considering order of receipt and impact to the ERCOT System.

3.1.6.9 Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities

(1) If ERCOT believes it cannot meet applicable reliability standards and has exercised all other reasonable options, and any actions taken pursuant to Section 3.1.4.6, Outage Coordination of Potential Transmission Emergency Conditions, have not resolved the situation, then ERCOT shall conduct a preliminary Outage Adjustment Evaluation (OAE) and issue an Advance Action Notice (AAN) pursuant to Section 6.5.9.3.1.1, Advance Action Notice.

(a) The AAN shall describe the reliability problem, the date and time that the possible Emergency Condition would begin, the date and time that the possible Emergency Condition would end, and a summary of the actions ERCOT believes it might take, including, if applicable, the amount of capacity it would seek from one or more OSAs based on the preliminary OAE. The AAN must state the earliest time at which ERCOT will issue OSAs, if an OSA is deemed necessary.

(b) ERCOT shall issue the AAN a minimum of 24 hours prior to issuing any OSA. Additionally, unless impracticable pursuant to paragraph (3)(f) below, OSAs should not be issued until eight Business Hours have elapsed following issuance of the AAN. ERCOT shall not issue an OSA under this Section unless it has first completed an updated OAE after these time periods have passed.

(c) Following the AAN, ERCOT may communicate with Market Participants about the reliability problem, however, ERCOT may not provide information about market conditions to a subset of Market Participants that is not generally available to all Market Participants.

(d) As conditions change, ERCOT shall, to the extent practicable, update the AAN in order to provide simultaneous notice to Market Participants.

(e) This section does not limit Transmission and/or Distribution Service Provider (TDSP) access to ERCOT data and communications.

(2) Before the time stated in the AAN when ERCOT will issue any OSAs, each QSE shall:

(a) Update its Resource COPs and the Outage Scheduler to the best of its ability to reflect any decisions to voluntarily delay or cancel any Outage so as to remove the Outage from updated OAE and OSA consideration;

(b) Notify ERCOT if a specific Resource cannot be considered for an OSA, for all or part of the period covered by the AAN, due to Resource reliability, compliance with contractual warranty obligations, or other reasons beyond the Resource's control; and

(c) Notify ERCOT of any Resource that is currently on Outage that the QSE agrees could be returned to service, upon receipt of an OSA, for all or part of the period covered by the AAN.

(3) If, after the earliest OSA issuance time has passed as noted in paragraph (1)(b) above, ERCOT continues to forecast an inability to meet applicable reliability standards after the updates to the Resource COPs and Outage Schedules, ERCOT may issue one or more OSAs.

(a) ERCOT may contact QSEs representing Resources for more information prior to conducting any updated OAE or issuing an OSA.

(b) ERCOT may not consider nuclear-powered Generation Resources for an OSA.

(c) ERCOT will not consider any Resource for an OSA if the Resource's QSE notified ERCOT prior to the earliest issuance time of any OSA stated in the AAN that the Resource cannot be considered for an OSA for the reasons specified in paragraph (2)(b) above.

(d) In order to determine which Outages to delay, ERCOT shall first consider the Outage duration, dividing the Outages in categories of zero to two days, two to four days, four to seven days, or more than seven days, then withdraw approval on a last in, first out basis within that duration category, so that shorter Outages are delayed first, and the timing of Outage submissions is considered within that category.

(e) After the earliest issuance time of the OSAs stated in the AAN, if the updated OAE shows that one or more OSAs is still necessary, ERCOT shall post a message to the ERCOT website stating that it will issue one or more OSAs and shall provide verbal notice to TSPs and QSEs via the Hotline. Subsequent to this notification, and for the entire period identified in the AAN, the QSE may not voluntarily modify the Resource's Outage, but is subject to the issuance of an OSA.

(f) ERCOT may only issue an OSA to the QSE for a Resource that has a Resource Outage in the Outage Scheduler during the timeframe of the forecasted Emergency Condition described above in this section.

(g) If the Resource Outage for which the OSA would be issued is scheduled to begin before eight Business Hours have elapsed following issuance of the AAN, ERCOT may issue the OSA prior to the beginning of the Resource Outage after the end of the 24-hour notice period.

(h) Following the receipt of an OSA, for the OSA Period:

(i) The QSE for the Resource may choose to show the Resource as OFF in the COP or may elect to leave the Resource On-Line due to equipment or reliability concerns or if the Resource Category is coal or lignite. If the QSE for the Resource intends to leave the Resource On-Line, it must communicate to the ERCOT control room the anticipated start and end time of the On-Line period. ERCOT will issue one or multiple RUC instructions to the QSE of the Resource for the anticipated On-Line period within the OSA Period for each Operating Day. While On-Line, the Resource must utilize a status of ONRUC and cannot opt out of RUC Settlement;

(ii) If the Resource remains On-Line pursuant to paragraph (i) above, it must remain at Low Sustained Limit (LSL) unless deployed above LSL by Security-Constrained Economic Dispatch (SCED);

(iii) If the Resource has a COP Resource Status of OFF at any point during the OSA Period, and ERCOT requires the Resource to be On-Line, or if ERCOT requires a Resource with a planned derate to maintain its capacity, ERCOT will issue a RUC instruction to the Resource's QSE for the required commitment period. While On-Line, the Resource must utilize a status of ONRUC and cannot opt out of RUC Settlement;

(iv) The QSE must update the Resource's Energy Offer Curve to $4,500/MWh for all MW levels from 0 MW to the High Sustained Limit (HSL) when the High System-Wide Offer Cap (HCAP) is in effect. If the Low-System Wide Offer Cap (LCAP) is in effect, the QSE must update the Resource's Energy Offer Curve equal to LCAP for all MW levels from 0 MW to HSL; and

[NPRR930: Replace paragraph (iv) above with the following upon system implementation:]

(iv) ERCOT shall create proxy Energy Offer Curves for the Resource under paragraph (4)(d)(iii) of Section 6.5.7.3, Security Constrained Economic Dispatch; and

(v) The QSE for the Resource cannot submit a Three Part Supply Offer into the Day-Ahead Market (DAM) for any Operating Day during the OSA Period.

(4) ERCOT shall work in good faith with the QSEs to reschedule any delayed or canceled Outages resulting from an AAN under paragraph (1) above, regardless of whether the Resource took voluntary actions or received an OSA. The Outage must be rescheduled so that it is completed within 120 days of the end of the OSA Period. ERCOT, in its sole discretion, may approve any Outage that is rescheduled due to an AAN or OSA even if it would cause the aggregate MW of approved Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity.

(a) If ERCOT issues an OSA, the QSE may submit a new request for approval of the Planned Outage schedule, however the new Outage may not begin prior to the end time of the OSA Period.

(b) If a transmission Outage was scheduled in coordination with a Resource Outage that is delayed, ERCOT shall also delay that transmission Outage when necessary.

(5) If insufficient capacity to meet the need described in the AAN is made available through the processes described in paragraphs (2) and (3) above, ERCOT may contact QSEs with Resources that are currently on Outage in the Outage Scheduler and that the QSE has agreed could be returned to service upon receipt of an OSA. ERCOT may issue an OSA to the QSE for any Resource that the QSE agrees can feasibly be returned to service during the period of the possible Emergency Condition described in the AAN.

(6) If system conditions change such that the need described in the AAN increases, ERCOT shall update the AAN and may repeat the process described in this section. For any subsequent iterations of this process, ERCOT shall issue the updated AAN with as much lead time as is practical prior to starting any subsequent OAE, but with a minimum of two hours' notice.

(7) The preliminary OAE may not assume total renewable production lower than the sum of the selected Wind-powered Generation Resource Production Potential (WGRPP) and PhotoVoltaic Generation Resource Production Potential (PVGRPP) forecasts for each hour less any reasonably expected severe weather impacts. The available capacity in ERCOT's planning assessment must include targeted reserve levels and include forecasted capacity available through DC Tie imports or curtailment of DC Tie exports, forecasted capacity provided from Settlement Only Distributed Generators (SODGs) and Settlement Only Transmission Generators (SOTGs), and forecasted capacity from price-responsive Demand based on information reported to ERCOT in accordance with Section 3.10.7.2.1, Reporting of Demand Response. ERCOT must post the following inputs to

the preliminary OAE to the ERCOT website within an hour of issuing an AAN, including but not limited to:

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

(k) SODG and SOTG forecasts;

(l) The forecast of capacity provided by price-responsive Demand;

(m) Any aggregate derating of Resource(s) and/or Forced Outage assumptions in total MWs; and

(n) Any aggregate fuel derating assumptions in total MWs.

[NPRR995: Replace paragraph (7) above with the following upon system implementation:]

(7) The preliminary OAE may not assume total renewable production lower than the sum of the selected Wind-powered Generation Resource Production Potential (WGRPP) and PhotoVoltaic Generation Resource Production Potential (PVGRPP) forecasts for each hour less any reasonably expected severe weather impacts. The available capacity in ERCOT's preliminary OAE must include targeted reserve levels and include forecasted capacity available through DC Tie imports or curtailment of DC Tie exports, forecasted capacity provided from Settlement Only Distributed Generators (SODGs), Settlement Only Transmission Generators (SOTGs), Settlement Only Distribution Energy Storage Systems (SODESSs), and Settlement Only Transmission Energy Storage Systems (SOTESSs), and forecasted capacity from price-responsive Demand based on information reported to ERCOT in accordance with Section 3.10.7.2.1, Reporting of Demand Response. ERCOT must post the following inputs to the preliminary OAE to the ERCOT website within an hour of issuing an AAN, including but not limited to:

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

(k) SODG, SOTG, SODESS, and SOTESS forecasts;

(l) The forecast of capacity provided by price-responsive Demand;

(m) Any aggregate derating of Resource(s) and/or Forced Outage assumptions in total MWs; and

(n) Any aggregate fuel derating assumptions in total MWs.

(8) Notwithstanding anything in this Section, ERCOT need not comply with any other requirement in this Section if the occurrence of an unforeseen Real-Time condition requires that ERCOT withdraw approval of one or more Resource Outages in order to meet applicable reliability standards. The unforeseen Real-Time condition cannot be the result of changes that Ancillary Services are procured to address. In exercising its discretion under this paragraph, ERCOT is not required to issue an AAN or OAE before issuing an OSA, but shall:

(a) Issue the OSA to the QSE of the Resource for the purpose of make whole compensation; and

(b) Present the justification for the out of market action to the Technical Advisory Committee (TAC) at its next meeting that is at least 14 Business Days after the OSA.

3.1.6.10 Opportunity Outage

(1) Opportunity Outages for Resources are a special category of Planned Outages that may be approved by ERCOT when a specific Resource has been forced Off-Line due to a Forced Outage and the Resource has been previously approved for a Planned Outage during the next two days.

(2) When a Forced Outage occurs on a Resource that has an approved Outage scheduled within the following two days, the Resource may remain Off-Line and start the approved Outage earlier than scheduled. The QSE must give as much notice as practicable to ERCOT.

(3) Opportunity Outages of Transmission Facilities may be approved by ERCOT when a specific Resource is Off-Line due to a Forced, Planned or Maintenance Outage. A TSP may request an Opportunity Outage at any time.

(4) When an Outage occurs on a Resource that has an approved Transmission Facilities Opportunity Outage request on file, the TSP may start the approved Outage as soon as practical after receiving authorization to proceed by ERCOT. ERCOT must give as much notice as practicable to the TSP.

3.1.6.11 Outage Returning Early

(1) A Resource that completes a Planned Outage early and wants to resume operation shall notify ERCOT of the early return prior to resuming service by making appropriate entries in the Current Operating Plan or Outage Scheduler if applicable as much in advance as practicable, but not later than at least two hours prior to beginning startup. Within two hours of receiving such request, ERCOT shall either:

(a) Approve the request unless, as a result of complying with the request, ERCOT cannot maintain system reliability or security with the Resource injection. In such a case, ERCOT shall issue a Verbal Dispatch Instruction (VDI) to the Resource's QSE to stay Off-Line; or

(b) Coordinate between the TSP and Resource Entity to schedule a time agreeable to both parties for the Resource to be Off-Line in the event if that a Transmission Facilities Outage requires the affected Resource to be Off-Line. If mutual agreement is not reached, then ERCOT shall decide on the appropriate time, after considering expected impacts on system security, future Outage plans, and participants and issue a VDI to the Resource's QSE to stay Off-Line.

(2) Before an early return from an Outage, a Resource Entity or QSE may inquire of ERCOT whether the Resource is expected to be decommitted by ERCOT upon its early return. If a Resource Entity or QSE is notified by ERCOT that the Resource will be decommitted if it returns early and the Resource Entity or QSE starts the Resource within the previously accepted or approved Outage period, then the QSE representing the Resource will not be

paid any decommitment compensation as otherwise would be provided for in Section 5.7, Settlement for RUC Process.

3.1.6.12 Resource Coming On-Line

(1) Before start-up and synchronizing On-Line, a Resource Entity or QSE may inquire of ERCOT whether the Resource is expected to be decommitted by ERCOT upon its coming On-Line. If a Resource Entity or QSE is notified by ERCOT that the Resource will be decommitted if the Resource comes On-Line and the Resource Entity or QSE starts the Resource, then the QSE representing the Resource will not be paid any decommitment compensation as otherwise would be provided for in Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource.

3.1.6.13 Maximum Daily Resource Planned Outage Capacity

(1) ERCOT shall calculate a maximum capacity of Resource Planned Outages, excluding Outages of nuclear-powered generation facilities and Outages of QFs that are subject to the exemption in paragraph (7) of Section 3.1.6, Outages of Resources Other than Reliability Resources, that should be allowed on each day of the next 60 months.

(a) For days more than seven days ahead of the Operating Day, the calculation of this Maximum Daily Resource Planned Outage Capacity will be based on seasonal assumptions, planned Resources that have met the criteria in Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, Planned Outages of nuclear Generation Resources, Planned Outages of QFs that are subject to the exemption in paragraph (7) of Section 3.1.6, and the long-term Load forecast. ERCOT shall update the calculation of the Maximum Daily Resource Planned Outage Capacity for the next 60 months twice per month.

(b) For days that are seven days or less prior to the Operating Day, the calculation of this Maximum Daily Resource Planned Outage Capacity will be based on the inputs used for the planning assessment for an OAE described in Section 3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities. ERCOT shall update the calculation of the Maximum Daily Resource Planned Outage Capacity for each hour of the next seven days on a rolling daily basis.

(c) ERCOT shall post the Maximum Daily Resource Planned Outage Capacity and aggregate MW of approved Resource Planned Outages at least twice per day on the ERCOT website for each day of the next 60 months.

(d) ERCOT shall post the Maximum Daily Resource Planned Outage Capacity and aggregate MW of approved Resource Planned Outages hourly on the ERCOT website for each hour of the next seven days.

(2) ERCOT may adjust the Maximum Daily Resource Planned Outage Capacity if, at any point in time, the actual aggregate Forced Outages and Maintenance Outages exceed the amount that is used in the assessment of the Maximum Daily Resource Planned Outage Capacity.

(3) ERCOT shall post on the ERCOT website the methodology it uses to calculate the Maximum Daily Resource Planned Outage Capacity in accordance with the parameters established by paragraphs (1) and (2) above. The methodology and any revisions thereto shall be approved by the ERCOT Board of Directors. ERCOT shall issue a Market Notice describing any revision and the justification for such revision and shall provide at least 14 days for stakeholder comment on the proposed revision unless ERCOT determines that, due to an actual or anticipated Emergency Condition, a shorter comment period is warranted. Upon adopting a change to the methodology, ERCOT shall post the revised methodology on the ERCOT website and issue a Market Notice announcing the posting.

3.1.6.14 Distribution Facility Outages Impacting Distribution Generation Resources and Distribution Energy Storage Resources

(1) A Distribution Service Provider (DSP) must notify the party designated by the Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) (Resource Entity or QSE) if the DSP plans to take an outage on any distribution facility that will impact the operation of a DGR or DESR. The Resource Entity for the DGR or DESR shall submit a Planned or Maintenance Resource Outage, as appropriate, to reflect the unavailability of the Resource due to the DSP outage. ERCOT may not reject a DGR or DESR Outage taken due to a DSP system outage, nor may ERCOT require the DSP to reschedule the outage. However, ERCOT may consult with the DSP about rescheduling the outage.

3.1.7 Reliability Resource Outages

(1) ERCOT shall evaluate requests for approval of an Outage of a Reliability Resource to determine if any one or a combination of proposed Outages may cause ERCOT to violate applicable reliability standards or exceed the Maximum Daily Resource Planned Outage Capacity. ERCOT's evaluations shall take into consideration factors including the following:

- (a) Load forecast;
- (b) All other known Outages; and
- (c) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software.

3.1.7.1 Timelines for Response by ERCOT on Reliability Resource Outages

(1) ERCOT shall approve requests for Planned Outages of Reliability Resources unless, in ERCOT's determination, the requested Planned Outage would cause ERCOT to violate applicable reliability standards or exceed the Maximum Daily Resource Planned Outage Capacity. ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between a Request for approval of a proposed Planned Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
No less than 30 days	Five Business Days after submission
Greater than 45 days	Five Business Days after submission

(2) ERCOT shall approve requests for Outages, other than Forced Outages or Level I Maintenance Outages, of Reliability Resources unless, in ERCOT's determination, the requested Outage would cause ERCOT to violate applicable reliability standards or exceed the Maximum Daily Resource Planned Outage Capacity. ERCOT shall approve or reject Maintenance Outages on Reliability Resources as follows:

Amount of time between a Request for approval of a proposed Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
Between three and eight days	0000 hours, two days before the start of the proposed Outage
Between nine and 30 days	Four days before the start of the proposed Outage

(3) ERCOT shall not be deemed to have approved the Outage request associated with the Planned Outage until ERCOT notifies the Single Point of Contact of its approval. ERCOT shall transmit approvals electronically.

(4) ERCOT, at its sole discretion, may relax the submission timing requirements in this Section.

3.1.7.2 Changes to an Approved Reliability Resource Outage Plan

(1) Once ERCOT has approved a Reliability Resource Planned Outage, the Resource Entity for the Reliability Resource may submit to ERCOT a change request by entering the change in the Outage Scheduler no later than 30 days before the scheduled start date of the approved Outage. ERCOT shall approve or reject the proposed change within 15 days of receiving the change request form. ERCOT may, at its discretion, relax the 30 day Notice requirement.

3.1.8 High Impact Transmission Element (HITE) Identification

(1) ERCOT, with input from Market Participants, shall develop a list of HITEs for review and approval at least annually by the TAC.

3.2 Analysis of Resource Adequacy

3.2.1 Calculation of Aggregate Resource Capacity

(1) ERCOT shall use Outages in the Outage Scheduler and, when applicable, the Resource Status from the Current Operating Plan (COP) to calculate the aggregate capacity from Generation Resources and Load Resources projected to be available in the ERCOT Region and in Forecast Zones in ERCOT. "Forecast Zones" have the same boundaries as the 2003 ERCOT Congestion Management Zones (CMZs). Each Resource will be mapped to a Forecast Zone during the registration process.

[NPRR1014 and NPRR1029: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall use Outages in the Outage Scheduler and, when applicable, the Resource Status from the Current Operating Plan (COP) to calculate the aggregate capacity from Generation Resources, Energy Storage Resources (ESRs), and Load Resources projected to be available in the ERCOT Region and in Forecast Zones in ERCOT. "Forecast Zones" have the same boundaries as the 2003 ERCOT Congestion Management Zones (CMZs). Each Resource will be mapped to a Forecast Zone during the registration process.

(2) On a rolling hourly basis, ERCOT shall calculate the aggregate hourly Generation Resource capacity and Load Resource capacity in the ERCOT Region and Forecast Zones projected to be available during each hour for the following seven days.

[NPRR1014 and NPRR1029: Replace applicable portions of paragraph (2) above with the following upon system implementation:]

(2) On a rolling hourly basis, ERCOT shall calculate the aggregate hourly Generation Resource capacity, ESR capacity, and Load Resource capacity in the ERCOT Region and Forecast Zones projected to be available during each hour for the following seven days.

(3) Projections of Generation Resource capacity from Intermittent Renewable Resources (IRRs) shall be consistent with capacity availability estimates, such as the effective Load carrying capability of wind, developed jointly between ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee and approved by the ERCOT Board

or typical production expectations consistent with expected wind profiles as appropriate for the scenario being studied.

[NPRR1029: Replace paragraph (3) above with the following upon system implementation:]

(3) Projections of generation capacity from Intermittent Renewable Resources (IRRs) and the intermittent renewable generation components of DC-Coupled Resources shall be consistent with capacity availability estimates, such as the effective Load carrying capability of wind, developed jointly between ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee and approved by the ERCOT Board or typical production expectations consistent with expected wind profiles as appropriate for the scenario being studied.

(4) ERCOT shall publish procedures describing the IRR forecasting process on the ERCOT website.

3.2.2 Demand Forecasts

(1) Monthly, ERCOT shall develop the weekly peak hour Demand forecast for the ERCOT Region and for the Forecast Zones based on the 36-Month Load Forecast as described in Section 3.12, Load Forecasting, for the following 36 months, starting with the second week. During the development of this forecast, ERCOT may consult with Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs), and other Market Participants that may have knowledge of potential Load growth.

(2) ERCOT may, at its discretion, publish on the MIS Secure Area, additional peak Demand analyses for periods beyond 36 months.

(3) ERCOT shall develop and publish hourly on the ERCOT website, peak Demand forecasts by Forecast Zone for each hour of the next seven days using the Seven-Day Load Forecast as described in Section 3.12.

(4) For purposes of Demand forecasting, ERCOT may choose to use the same forecast as that used for the Load forecast.

(5) ERCOT shall publish procedures describing the forecasting process on the ERCOT website.

3.2.3 Short-Term System Adequacy Reports

(1) ERCOT shall generate and post short-term adequacy reports on the ERCOT website. ERCOT shall update these reports hourly following updates to the Seven-Day Load Forecast, except where noted otherwise. The short-term adequacy reports will provide:

(a) For Generation Resources, the available On-Line Resource capacity for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria;

(b) The total system-wide capacity of Resource Outages as reflected in the Outage Scheduler that are accepted or approved. The Resource Outage capacity amount shall be based from each Resource's current Seasonal High Sustained Limit (HSL) and posted each hour for the top of each Operating Hour for the next 168 hours. This posted information will exclude specific Resource information and Outages related to Mothballed or Decommissioned Generation Resources, and will be aggregated on a Forecast Zone basis in three categories:

(i) IRRs with an Outage Scheduler nature of work other than "New Equipment Energization";

(ii) Other Resources with an Outage Scheduler nature of work other than "New Equipment Energization"; and

(iii) Resources with an Outage Scheduler nature of work "New Equipment Energization";

(c) For Load Resources, the available capacity for each hour aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of ONRGL, ONCLR, or ONRL;

(d) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;

(e) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF or OFFNS and temporal constraints; and

(f) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, aggregated by Forecast Zone, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1 excluding SHUTDOWN.

(g) The available capacity for each hour for the next seven days. For day one, and for day two following the execution of the Day-Ahead Reliability Unit Commitment (DRUC) on day one, the available capacity will be the sum of the values calculated in paragraphs (a) and (e) above, except that for IRRs the forecasted output will be used instead of COP values, and Direct Current Tie (DC Tie) exports will be subtracted. For the remaining hours of the seven days, the available capacity will be calculated as the sum of the Seasonal HSLs for non-IRR Generation Resources including seasonal Private Use Network capacity and the forecasted output for IRRs minus the total capacity of accepted or approved Resource Outages.

(h) The available capacity for reserves for each hour, which will be the available capacity calculated in paragraph (g) above minus the forecasted Demand for that hour.

[NPRR962, NPRR1007, and NPRR1029: Replace applicable portions of Section 3.2.3 above with the following upon system implementation for NPRR962 or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

3.2.3 Short-Term System Adequacy Reports

(1) ERCOT shall generate and post short-term adequacy reports on the ERCOT website. ERCOT shall update these reports hourly following updates to the Seven-Day Load Forecast, except where noted otherwise. The short-term adequacy reports will provide:

(a) For Generation Resources, the available On-Line Resource capacity for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria;

(b) The total system-wide capacity of Resource Outages as reflected in the Outage Scheduler that are accepted or approved. The Resource Outage capacity amount shall be based from each Resource's current Seasonal High Sustained Limit (HSL) and posted each hour for the top of each Operating Hour for the next 168 hours. This posted information will exclude specific Resource information and Outages related to Mothballed or Decommissioned Generation Resources, and will be aggregated on a Forecast Zone basis in three categories:

(i) IRRs and the intermittent renewable generation component of each DC-Coupled Resource with an Outage Scheduler nature of work other than "New Equipment Energization";

(ii) Other Resources with an Outage Scheduler nature of work other than "New Equipment Energization"; and

(iii) Resources with an Outage Scheduler nature of work "New Equipment Energization";

(c) For Load Resources, the available capacity for each hour aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of ONL;

(d) The total capability of Resources available to provide the following Ancillary Service combinations, using COPs submitted by QSEs for the first seven days and capped by the COP limits for individual Resources. A Resource's capability shall only be included in the sums below if the Resource Status allows the Resource to provide at least one of the Ancillary Services within the sum:

(i) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;

(ii) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;

(iii) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;

(iv) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;

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

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

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

(viii) Capacity to provide Reg-Down;

(e) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;

(f) For Generation Resources, the available Off-Line Resource capacity that can be started for each hour, aggregated by Forecast Zone, using the COP for the first seven days and considering Resources with a COP Resource Status of OFF and temporal constraints; and

(g) Following each Hourly Reliability Unit Commitment (HRUC), the available On-Line capacity from Generation Resources, aggregated by Forecast Zone, based on Real-Time telemetry, for which the COP Resource Status is OFF, OUT, or EMR for all hours within the HRUC Study Period. The available On-Line capacity will consider those Resources with a Real-Time Resource Status listed in paragraph (5)(b)(i) of Section 3.9.1 excluding SHUTDOWN.

(h) For each Direct Current Tie (DC Tie), the sum of any ERCOT-approved DC Tie Schedules for each 15-minute interval for the first seven days. The sum shall be displayed as an absolute value and classified as a net import or net export.

(i) The available capacity for each hour for the next seven days. For day one, and for day two following the execution of the Day-Ahead Reliability Unit

Commitment (DRUC) on day one, the available capacity will be the sum of the values calculated in paragraphs (a) and (f) above, except that for IRRs the forecasted output will be used instead of COP values, and DC Tie exports will be subtracted. For the remaining hours of the seven days, the available capacity will be calculated as the sum of the Seasonal HSLs for non-IRR Generation Resources including seasonal Private Use Network capacity and the forecasted output for IRRs minus the total capacity of accepted or approved Resource Outages.

(j) The available capacity for reserves for each hour, which will be the available capacity calculated in paragraph (i) above minus the forecasted Demand for that hour.

3.2.4 [RESERVED]

3.2.5 Publication of Resource and Load Information

(1) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System and, if applicable, for each Disclosure Area, the information derived from the first complete execution of Security-Constrained Economic Dispatch (SCED) in each 15-minute Settlement Interval. The Disclosure Area is the 2003 ERCOT CMZs. Posting requirements will be applicable to Generation Resources and Controllable Load Resources physically located in the defined Disclosure Area. This information shall not be posted if the posting of the information would reveal any individual Market Participant's Protected Information. The information posted by ERCOT shall include:

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(1) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System and, if applicable, for each Disclosure Area, the information derived from each execution of SCED. The Disclosure Area is the 2003 ERCOT CMZs. Posting requirements will be applicable to Generation Resources, ESRs, and Controllable Load Resources physically located in the defined Disclosure Area. This information shall not be posted if the posting of the information would reveal any individual Market Participant's Protected Information. The information posted by ERCOT shall include:

(a) An aggregate energy supply curve based on non-IRR Generation Resources with Energy Offer Curves that are available to SCED. The energy supply curves will be calculated beginning at the sum of the Low Sustained Limits (LSLs) and ending at the sum of the HSLs for non-IRR Generation Resources with Energy Offer Curves, with the dispatch for each Generation Resource constrained between the Generation Resource's LSL and HSL. The result will represent the ERCOT System energy supply curve economic dispatch of the non-IRR Generation Resources with Energy Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

(b) An aggregate energy supply curve based on Wind-powered Generation Resources (WGRs) with Energy Offer Curves that are available to SCED. The energy supply curves will be calculated beginning at the sum of the LSLs and ending at the sum of the HSLs for WGRs with Energy Offer Curves, with the dispatch for each WGR constrained between the WGR's LSL and HSL. The result will represent the ERCOT System energy supply curve economic dispatch of the WGRs with Energy Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

(c) An aggregate energy supply curve based on PhotoVoltaic Generation Resources (PVGRs) with Energy Offer Curves that are available to SCED. The energy supply curves will be calculated beginning at the sum of the LSLs and ending at the sum of the HSLs for PVGRs with Energy Offer Curves, with the dispatch for each PVGR constrained between the PVGR's LSL and HSL. The result will represent the ERCOT System energy supply curve economic dispatch of the PVGRs with Energy Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

[NPRR1014: Insert paragraph (d) below upon system implementation and renumber accordingly:]

(d) An aggregated energy supply and demand curve based on Energy Bid/Offer Curves that are available to SCED. The curves will be calculated beginning at the sum of the LSLs and ending at the sum of the HSLs for the Energy Bid/Offer Curves, with the dispatch for each Resource constrained between the Resource's LSL and HSL. The result will represent the ERCOT System energy supply and demand curve economic dispatch of the ESRs with Energy Bid/Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

(d) The sum of LSLs, sum of Output Schedules, and sum of HSLs for Generation Resources without Energy Offer Curves;

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

(e) The sum of LSLs, sum of Output Schedules, and sum of HSLs for Generation Resources without Energy Offer Curves and ESRs without Energy Bid/Offer Curves;

(e) The sum of the Base Points, High Ancillary Service Limit (HASL) and Low Ancillary Service Limit (LASL) of non-IRR Generation Resources with Energy Offer Curves, sum of the Base Points, HASL and LASL of WGRs with Energy Offer Curves, sum of the Base Points, HASL and LASL of PVGRs with Energy Offer Curves, and the sum of the Base Points, HASL and LASL of all remaining Generation Resources dispatched in SCED;

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(f) The sum of the Base Points of non-IRR Generation Resources with Energy Offer Curves, sum of the Base Points of WGRs with Energy Offer Curves, sum of the Base Points of PVGRs with Energy Offer Curves, sum of the Base Points of ESRs with Energy Bid/Offer Curves, and the sum of the Base Points of all remaining Resources dispatched in SCED;

(f) The sum of the telemetered Generation Resource net output used in SCED; and

(g) An aggregate energy Demand curve based on the Real-Time Market (RTM) Energy Bid curves available to SCED. The energy Demand curve will be calculated beginning at the sum of the Low Power Consumptions (LPCs) and ending at the sum of the Maximum Power Consumptions (MPCs) for Controllable Load Resources with RTM Energy Bids, with the dispatch for each Controllable Load Resource constrained between the Controllable Load Resource's LPC and MPC. The result will represent the ERCOT System Demand response capability available to SCED of the Controllable Load Resources with RTM Energy Bids at various pricing points, not taking into consideration any physical limitations of the ERCOT System.

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

(h) An aggregate energy Demand curve based on the Real-Time Market (RTM) Energy Bid curves available to SCED. The energy Demand curve will be calculated beginning at the sum of the Low Power Consumptions (LPCs) and ending at the sum of the Maximum Power Consumptions (MPCs), with the dispatch for each Controllable Load Resource constrained between the Controllable Load Resource's LPC and MPC. The result will represent the ERCOT System Demand response capability available to SCED of the

Controllable Load Resources with RTM Energy Bids at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

[NPRR1007 and NPRR1014: Insert applicable portions of paragraphs (i)-(k) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(i) The aggregate Ancillary Service Offers (prices and quantities) in the RTM, for each type of Ancillary Service. For Responsive Reserve (RRS) and ERCOT Contingency Reserve Service (ECRS), ERCOT shall separately post aggregated offers from Generation Resources, Energy Storage Resources (ESRs), Controllable Load Resources, and Load Resources other than Controllable Load Resources. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers;

(j) The sum of the Base Points of ESRs in discharge mode; and

(k) The sum of the Base Points of ESRs in charge mode.

(2) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System the following information derived from the first complete execution of SCED in each 15-minute Settlement Interval:

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(2) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System the following information derived from each execution of SCED:

(a) Each telemetered Dynamically Scheduled Resource (DSR) Load, and the telemetered DSR net output(s) associated with each DSR Load; and

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

(b) The actual ERCOT Load as determined by subtracting the DC Tie Resource actual telemetry from the sum of the telemetered Generation Resource net output as used in SCED.

(3) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website the following information for the ERCOT System and, if applicable, for each Disclosure Area from the Day-Ahead Market (DAM) for each hourly Settlement Interval:

(a) An aggregate energy supply curve based on all energy offers that are available to the DAM, not taking into consideration Resource Startup Offer or Minimum-Energy Offer or any physical limitations of the ERCOT System. The result will represent the energy supply curve at various pricing points for energy offers available in the DAM;

(b) Aggregate minimum energy supply curves based on all Minimum-Energy Offers that are available to the DAM;

(c) An aggregate energy Demand curve based on the DAM Energy Bid curves available to the DAM, not taking into consideration any physical limitations of the ERCOT System;

(d) The aggregate amount of cleared energy bids and offers including cleared Minimum-Energy Offer quantities;

(e) The aggregate Ancillary Service Offers (prices and quantities) in the DAM, for each type of Ancillary Service regardless of a Resource's On-Line or Off-Line status. For Responsive Reserve (RRS), ERCOT shall separately post aggregated offers from Resources providing Primary Frequency Response, Fast Frequency Response (FFR), and Load Resources controlled by high-set under-frequency relays. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers;

(f) The aggregate Self-Arranged Ancillary Service Quantity, for each type of service, by hour. For RRS, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources providing Primary Frequency Response, FFR, and Load Resources controlled by high-set under-frequency relays;

(g) The aggregate amount of cleared Ancillary Service Offers. For RRS, ERCOT shall separately post aggregated Ancillary Service Offers from Resources providing Primary Frequency Response, FFR, and Load Resources controlled by high-set under-frequency relays; and

(h) The aggregate Point-to-Point (PTP) Obligation bids (not-to-exceed price and quantities) for the ERCOT System and the aggregate PTP Obligation bids that sink in the Disclosure Area for each Disclosure Area.

[NPRR863, NPRR1007, NPRR1014, and NPRR1015: Replace applicable portions of paragraph (3) above with the following upon system implementation of NPRR863 for

NPRR863 and NPRR1015; or upon system implementation for NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

(3) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website the following information for the ERCOT System and, if applicable, for each Disclosure Area from the DAM for each hourly Settlement Interval:

(a) An aggregate energy supply curve based on all energy offers that are available to the DAM, including the offer portion of Energy Bid/Offer Curves submitted for ESRs, not taking into consideration Resource Startup Offer or Minimum-Energy Offer or any physical limitations of the ERCOT System. The result will represent the energy supply curve at various pricing points for energy offers available in the DAM;

(b) Aggregate minimum energy supply curves based on all Minimum-Energy Offers that are available to the DAM;

(c) An aggregate energy Demand curve based on the DAM Energy Bid curves and including the bid portion of Energy Bid/Offer Curves available to the DAM, not taking into consideration any physical limitations of the ERCOT System;

(d) The aggregate amount of cleared energy bids and offers including cleared Minimum-Energy Offer quantities;

(e) The aggregate Ancillary Service Offers (prices and quantities) in the DAM, for each type of Ancillary Service regardless of a Resource's On-Line or Off-Line status and including Ancillary Service Only Offers. For RRS, ERCOT shall separately post aggregated offers from Resources providing Primary Frequency Response (including Ancillary Service Only Offers), Fast Frequency Response (FFR), and Load Resources controlled by high-set under-frequency relays. For ERCOT Contingency Reserve Service (ECRS), ERCOT shall separately post aggregated offers from Resources that are SCED-dispatchable (including Ancillary Service Only Offers) and those that are manually dispatched. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers;

(f) The aggregate Self-Arranged Ancillary Service Quantity, for each type of service, by hour. For RRS, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources providing Primary Frequency Response, FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources that are SCED-dispatchable and those that are manually dispatched;

(g) The aggregate amount of cleared Resource-specific Ancillary Service Offers and Ancillary Service Only Offers. For RRS, ERCOT shall separately post aggregated Ancillary Service Offers from Resources providing Primary

Frequency Response (including Ancillary Service Only Offers), FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS, ERCOT shall separately post aggregated Ancillary Service Offers from Resources that are SCED-dispatchable (including Ancillary Service Only Offers) and those that are manually dispatched; and

(h) The aggregate Point-to-Point (PTP) Obligation bids (not-to-exceed price and quantities) for the ERCOT System and the aggregate PTP Obligation bids that sink in the Disclosure Area for each Disclosure Area.

(4) ERCOT shall post on the ERCOT website the following information for each Resource for each 15-minute Settlement Interval 60 days prior to the current Operating Day:

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(4) ERCOT shall post on the ERCOT website the following information for each Resource for each execution of SCED 60 days prior to the current Operating Day:

(a) The Generation Resource name and the Generation Resource's Energy Offer Curve (prices and quantities):

(i) As submitted;

(ii) As submitted and extended (or truncated) with proxy Energy Offer Curve logic by ERCOT to fit to the operational HSL and LSL values that are available for dispatch by SCED; and

(iii) As mitigated and extended for use in SCED, including the Incremental and Decremental Energy Offer Curves for DSRs;

[NPRR1000: Replace paragraph (iii) above with the following upon system implementation:]

(iii) As mitigated and extended for use in SCED;

[NPRR1007 and NPRR1014: Insert applicable portions of paragraph (b) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014; and renumber accordingly:]

(b) The Resource name and the Resource's Ancillary Service Offer Curve (prices and quantities) for each type of Ancillary Service:

(i) As submitted; and

(ii) As submitted and extended with proxy Ancillary Service Offer Curve logic by ERCOT.

(b) The Load Resource name and the Load Resource's bid to buy (prices and quantities);

(c) The Generation Resource name and the Generation Resource's Output Schedule;

(d) For a DSR, the DSR Load and associated DSR name and DSR net output;

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

(e) The Generation Resource name and actual metered Generation Resource net output;

(f) The self-arranged Ancillary Service by service for each QSE;

(g) The following Generation Resource data using a single snapshot during the first SCED execution in each Settlement Interval:

(i) The Generation Resource name;

(ii) The Generation Resource status;

(iii) The Generation Resource HSL, LSL, HASL, LASL, High Dispatch Limit (HDL), and Low Dispatch Limit (LDL);

(iv) The Generation Resource Base Point from SCED;

(v) The telemetered Generation Resource net output used in SCED;

(vi) The Ancillary Service Resource Responsibility for each Ancillary Service;

(vii) The Generation Resource Startup Cost and minimum energy cost used in the Reliability Unit Commitment (RUC); and

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (g) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(h) The following Generation Resource data using a snapshot from each execution of SCED:

(i) The Generation Resource name;

(ii) The Generation Resource status;

(iii) The Generation Resource HSL, LSL, High Dispatch Limit (HDL), and Low Dispatch Limit (LDL);

(iv) The Generation Resource Base Point from SCED;

(v) The telemetered Generation Resource net output used in SCED;

(vi) The Ancillary Service Resource awards for each Ancillary Service;

(vii) The Generation Resource Startup Cost and minimum energy cost used in the Reliability Unit Commitment (RUC);

(viii) The telemetered Normal Ramp Rates;

(ix) The telemetered Ancillary Service capabilities; and

(h) The following Load Resource data using a single snapshot during the first SCED execution in each Settlement Interval:

(i) The Load Resource name;

(ii) The Load Resource status;

(iii) The MPC for a Load Resource;

(iv) The LPC for a Load Resource;

(v) The Load Resource HASL, LASL, HDL, and LDL, for a Controllable Load Resource that has a Resource Status of ONRGL or ONCLR for the interval snapshot;

(vi) The Load Resource Base Point from SCED, for a Controllable Load Resource that has a Resource Status of ONRGL or ONCLR for the interval snapshot;

(vii) The telemetered real power consumption; and

(viii) The Ancillary Service Resource Responsibility for each Ancillary Service.

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (h) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(i) The following Load Resource data using a snapshot from each execution of SCED:

(i) The Load Resource name;

(ii) The Load Resource status;

(iii) The MPC for a Load Resource;

(iv) The LPC for a Load Resource;

(v) The Load Resource HDL and LDL, for a Controllable Load Resource that has a Resource Status of ONL;

(vi) The Load Resource Base Point from SCED, for a Controllable Load Resource that has a Resource Status of ONL;

(vii) The telemetered real power consumption;

(viii) The Ancillary Service Resource awards for each Ancillary Service;

(ix) The telemetered self-provided Ancillary Service amount for each Ancillary Service;

(x) The telemetered Normal Ramp Rates;

(xi) The telemetered Ancillary Service capabilities; and

(j) The ESR name and the ESR's Energy Bid/Offer Curve (prices and quantities):

(i) As submitted; and

(ii) As submitted and extended with proxy Energy Offer Curve logic by ERCOT to fit to the operational HSL and LSL values that are available for dispatch by SCED;

(k) The following ESR data using a snapshot from each execution of SCED:

(i) The ESR name;

(ii) The ESR status;

(iii) The ESR HSL, LSL, High Dispatch Limit (HDL), and Low Dispatch Limit (LDL);

(iv) The ESR Base Point from SCED;

(v) The telemetered ESR net output used in SCED;

(vi) The Ancillary Service Resource awards for each Ancillary Service;

(vii) The telemetered Normal Ramp Rates;

(viii) The telemetered Ancillary Service capabilities; and

(ix) The telemetered State of Charge in MWh.

[NPRR1007 and NPRR1058: Insert applicable portions of paragraph (5) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1058; and renumber accordingly:]

(5) ERCOT shall post on the ERCOT website for each Resource for each Operating Hour 60 days prior to the current Operating Day a count of the number of times for each Ancillary Service that the Resource's Ancillary Service Offer quantity or price was updated within the Operating Period. ERCOT shall post on the ERCOT website for each Resource for each Operating Hour 60 days prior to the current Operating Day, a count of the number of times a Resource's Energy Offer quantity or price was updated within the Operating Hour, including any reason accompanying the update.

(5) If any Real-Time Locational Marginal Price (LMP) exceeds 50 times the Fuel Index Price (FIP) during any 15-minute Settlement Interval for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion of any Generation Resource's as-submitted and as-mitigated and extended Energy Offer Curve that is at or above 50 times the FIP for each 15-minute Settlement Interval seven days after the applicable Operating Day.

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(6) If any Real-Time Locational Marginal Price (LMP) exceeds 50 times the Fuel Index Price (FIP) during any SCED interval for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion of any Generation Resource's as-submitted and as-mitigated and extended Energy Offer Curve or any ESR's as-submitted and as-mitigated and extended Energy Bid/Offer Curve that is at or above 50 times the FIP for that SCED interval seven days after the applicable Operating Day.

(6) If any Market Clearing Price for Capacity (MCPC) for an Ancillary Service exceeds 50 times the FIP for any Operating Hour in a DAM or Supplemental Ancillary Services Market (SASM) for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion on any Resource's Ancillary Service Offer that is at or above 50 times the FIP for that Ancillary Service for each Operating Hour seven days after the applicable Operating Day.

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(7) If any Market Clearing Price for Capacity (MCPC) for an Ancillary Service exceeds 50 times the FIP for any Operating Hour in a DAM or any SCED interval in the RTM for the applicable Operating Day, ERCOT shall post on the ERCOT website the portion on any Resource's Ancillary Service Offer that is at or above 50 times the FIP for that Ancillary Service for that Operating Hour for the DAM or SCED interval for the RTM seven days after the applicable Operating Day.

(7) ERCOT shall post on the ERCOT website the offer price and the name of the Entity submitting the offer for the highest-priced offer selected or Dispatched by SCED three days after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the ERCOT website.

(8) ERCOT shall post on the ERCOT website the bid price and the name of the Entity submitting the bid for the highest-priced bid selected or Dispatched by SCED three days after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced bids selected, all Entities shall be identified on the ERCOT website.

(9) ERCOT shall post on the ERCOT website the offer price and the name of the Entity submitting the offer for the highest-priced Ancillary Service Offer selected in the DAM for each Ancillary Service three days after the end of the applicable Operating Day. This same report shall also include the highest-priced Ancillary Service Offer selected for any SASMs cleared for that same Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the ERCOT website. The report shall specify whether the Ancillary Service Offer was selected in a DAM or a SASM.

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(10) ERCOT shall post on the ERCOT website the offer price and the name of the Entity submitting the offer for the highest-priced Ancillary Service Offer selected in the DAM or RTM for each Ancillary Service three days after the end of the applicable Operating Day. If multiple Entities submitted the highest-priced offers selected, all Entities shall be identified on the ERCOT website. The report shall specify whether the Ancillary Service Offer was selected in a DAM or RTM.

(10) ERCOT shall post on the ERCOT website for each Operating Day the following information for each Resource:

(a) The Resource name;

(b) The name of the Resource Entity;

(c) Except for Load Resources that are not SCED qualified, the name of the Decision Making Entity (DME) controlling the Resource, as reflected in the Managed Capacity Declaration submitted by the Resource Entity in accordance with Section 3.6.2, Decision Making Entity for a Resource; and

(d) Flag for Reliability Must-Run (RMR) Resources.

(11) ERCOT shall post on the ERCOT website the following information from the DAM for each hourly Settlement Interval for the applicable Operating Day 60 days prior to the current Operating Day:

(a) The Generation Resource name and the Generation Resource's Three-Part Supply Offer (prices and quantities), including Startup Offer and Minimum-Energy Offer, available for the DAM;

(b) For each Settlement Point, individual DAM Energy-Only Offer Curves available for the DAM and the name of the QSE submitting the offer;

(c) The Resource name and the Resource's Ancillary Service Offers available for the DAM;

[NPRR1007 and NPRR1014: Insert applicable portions of paragraph (d) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014; and renumber accordingly:]

(d) The Ancillary Service Only Offer for each Ancillary Service and the name of the QSE submitting the offer;

(d) For each Settlement Point, individual DAM Energy Bids available for the DAM and the name of the QSE submitting the bid;

(e) For each Settlement Point, individual PTP Obligation bids available to the DAM that sink at the Settlement Point and the QSE submitting the bid;

(f) The awards for each Ancillary Service from DAM for each Generation Resource;

(g) The awards for each Ancillary Service from DAM for each Load Resource;

(h) The award of each Three-Part Supply Offer from the DAM and the name of the QSE receiving the award;

(i) For each Settlement Point, the award of each DAM Energy-Only Offer from the DAM and the name of the QSE receiving the award;

(j) For each Settlement Point, the award of each DAM Energy Bid from the DAM and the name of the QSE receiving the award; and

(k) For each Settlement Point, the award of each PTP Obligation bid from the DAM that sinks at the Settlement Point, including whether or not the PTP Obligation bid was linked to an Option, and the QSE submitting the bid.

[NPRR1014: Insert items (m)-(o) below upon system implementation:]

(m) The ESR name and the ESR's Energy Bid/Offer Curve (prices and quantities), available for the DAM;

(n) The awards for each Ancillary Service from the DAM for each ESR; and

(o) The award of each Energy Bid/Offer Curve from the DAM and the name of the QSE receiving the award.

(12) ERCOT shall post on the ERCOT website the following information from any applicable SASMs for each hourly Settlement Interval for the applicable Operating Day 60 days prior to the current Operating Day:

(a) The Resource name and the Resource's Ancillary Service Offers available for any applicable SASMs;

(b) The awards for each Ancillary Service from any applicable SASMs for each Generation Resource; and

(c) The awards for each Ancillary Service from any applicable SASMs for each Load Resource.

[NPRR1007: Delete paragraph (12) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

3.2.5.1 Unregistered Distributed Generation Reporting Requirements for Non Opt-In Entities

(1) This Section describes the data that shall be submitted to ERCOT for the unregistered Distributed Generation (DG) behind Non-Opt-In Entity (NOIE) boundary metering points.

(2) Within ten Business Days after the end of each quarter, each NOIE shall submit to ERCOT electronically the required data described below as of the last day of the prior quarter by submitting the designated form provided on the ERCOT website. NOIEs that have an unregistered DG capacity of more than two MW, based upon the aggregate capacity of all sites that are less than 50 kW, shall report the total of all unregistered DG

MW capacity, inclusive of systems used to support self-serve Load. All other NOIEs shall report the aggregate unregistered DG capacity of only those sites greater than or equal to 50 kW, inclusive of systems used to support self-serve Load. NOIEs shall report their capacity by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

(3) NOIEs not reporting DG MW capacity less than 50 kW on a quarterly basis as described in paragraph (2) above shall submit to ERCOT by March 1 of each year their annual aggregate unregistered DG MW capacity, inclusive of systems used to support self-serve Load, for the preceding calendar year. NOIEs shall report their capacity by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

(4) Each of the above reports is required to include only the capacity known to the NOIE at the time that its report is being prepared, and shall not require the NOIE to conduct new survey activities for its service territory to identify unknown unregistered DG installations. Any NOIE may obtain a reporting exemption for the annual report required in 2020 by notifying ERCOT of the exemption claim in writing on or before March 1, 2020.

3.2.5.2 Unregistered Distributed Generation Reporting Requirements for Competitive Areas

(1) The data for competitive areas will be compiled from the reports submitted to ERCOT as found in the Load Profiling Guide, Appendix D, Load Profiling Decision Tree, DG Tab.

3.2.5.3 Unregistered Distributed Generation Reporting Requirements for ERCOT

(1) Within 30 days after the end of each quarter, ERCOT shall publish the unregistered DG report on the ERCOT website. This report shall include the aggregated data compiled for NOIE and competitive areas. This report shall include the total unregistered DG MW capacity, as provided in accordance with Section 3.2.5.1, Unregistered Distributed

Generation Reporting Requirements for Non Opt-In Entities, and Section 3.2.5.2, Unregistered Distributed Generation Reporting Requirements for Competitive Areas, above, by Load Zone and by primary fuel type as follows:

(a) Solar;

(b) Wind;

(c) Other renewable; and

(d) Other non-renewable.

(2) ERCOT shall update the appropriate TAC subcommittee on an as needed basis on the unregistered DG report.

3.2.6 ERCOT Planning Reserve Margin

(1) ERCOT shall calculate the Planning Reserve Margin (PRM) for each Peak Load Season as follows:

$$\mathbf{PRM}_{s,\,i} \quad = \quad (\mathbf{TOTCAP}_{s,\,i} - \mathbf{FIRMPKLD}_{s,\,i}) \;/\; \mathbf{FIRMPKLD}_{s,\,i}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$PRM_{s,\,i}$	%	*Planning Reserve Margin*—The Planning Reserve Margin for the Peak Load Season *s* for year *i*.
$TOTCAP_{s,\,i}$	MW	*Total Capacity*—Total Capacity available during the Peak Load Season *s* for the year *i*.
$FIRMPKLD_{s,\,i}$	MW	*Firm Peak Load*—Firm Peak Load for the Peak Load Season *s* for the year *i*.
i	None	Year.
s	None	Peak Load Season.

3.2.6.1 Minimum ERCOT Planning Reserve Margin Criterion

(1) The minimum ERCOT PRM criterion is approved by the ERCOT Board. ERCOT shall periodically review and recommend to the ERCOT Board any changes to the minimum ERCOT PRM to help ensure adequate reliability of the ERCOT System. ERCOT shall update the minimum PRM on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall post the revised minimum PRM to the ERCOT website prior to implementation.

3.2.6.2 ERCOT Planning Reserve Margin Calculation Methodology

(1) ERCOT shall prepare and publish on the ERCOT website, at least annually, the Report on Capacity, Demand and Reserves in the ERCOT Region containing an estimate of the

PRM for the current Peak Load Seasons as well as a minimum of ten future summer and winter peak Load periods. The format and content of this report shall be developed by ERCOT, and subject to TAC approval. The estimate of the PRM shall be based on the methodology in Section 3.2.6.2.1, Peak Load Estimate, and Section 3.2.6.2.2, Total Capacity Estimate.

(2) ERCOT shall prepare and publish on the ERCOT website, no later than 60 days after the end of each summer and winter Peak Load Season, updates to the variable WINDPEAKPCT, defined in Section 3.2.6.2.2. The published information will also include the following inputs and associated formulas used in the variable calculations:

(a) The date, hour, and associated Load for the 20 highest system-wide peak Load hours by region, season and year;

(b) The wind capacity for the 20 highest system-wide peak Load hours by region, season and year; and

(c) The installed wind capacity by region and year.

3.2.6.2.1 Peak Load Estimate

(1) ERCOT shall prepare, at least annually, a forecast of the total peak Load for both summer and winter Peak Load Seasons for the current year and a minimum of ten future years using an econometric forecast, taking into account econometric inputs, weather conditions, demographic data and other variables as deemed appropriate by ERCOT. The firm Peak Load Season estimate shall be determined by the following equation:

$$\mathbf{FIRMPKLD}_{s,i} = \mathbf{TOTPKLD}_{s,i} - \mathbf{LRRRS}_{s,i} - \mathbf{LRNSRS}_{s,i} - \mathbf{ERS}_{s,i} - \mathbf{CLR}_{s,i} - \mathbf{ENERGYEFF}_{s,i}$$

[NPRR863: Replace the formula "FIRMPKLD $_{s,i}$" above with the following upon system implementation:]

$$\mathbf{FIRMPKLD}_{s,i} = \mathbf{TOTPKLD}_{s,i} - \mathbf{LRRRS}_{s,i} - \mathbf{LRECRS}_{s,i} - \mathbf{LRNSRS}_{s,i} - \mathbf{ERS}_{s,i} - \mathbf{CLR}_{s,i} - \mathbf{ENERGYEFF}_{s,i}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
FIRMPKLD $_{s,i}$	MW	*Firm Peak Load Estimate*—The Firm Peak Load Estimate for the Peak Load Season *s* for the year *i*.
TOTPKLD $_{s,i}$	MW	*Total Peak Load Estimate*—The Total Peak Load Estimate for the Peak Load Season *s* for the year *i*.
LRRRS $_{s,i}$	MW	*Load Resource providing RRS*—The amount of RRS a Load Resource is providing for the Peak Load Season *s* for the year *i*.

[NPRR863: Insert the variable “LRECRS $_{s, i}$” below upon system implementation:]

LRECRS $_{s, i}$	MW	*Load Resource providing ECRS*—The amount of ECRS a Load Resource is providing for the Peak Load Season *s* for the year *i*.

<table>
<tr><td>LRNSRS $_{s, i}$</td><td>MW</td><td><i>Load Resource providing Non-Spinning Reserve (Non-Spin)</i>—The estimated amount of Non-Spin that Load Resources are providing for the Peak Load Season <i>s</i> for the year <i>i</i>.</td></tr>
<tr><td>ERS $_{s, i}$</td><td>MW</td><td><i>Emergency Response Service (ERS)</i>—The estimated amount of ERS for the Peak Load Season <i>s</i> for the year <i>i</i> calculated as follows:
<table>
<tr><th>Year (i)</th><th>Winter Peak Load</th><th>Summer Peak Load</th></tr>
<tr><td>Current Year (i = 1)</td><td>The simple average of the amount of ERS procured by ERCOT for the current year Standard Contract Term of December 1 to March 31 for the ERS Time Periods covering all or any part of Hour Ending 0600 and Hour Ending 1800.</td><td>The amount of ERS procured by ERCOT for the current year Standard Contract Term of June 1 through September 30 for an ERS Time Period covering all or any part of Hour Ending 1800.</td></tr>
<tr><td>Second Year (i = 2)</td><td>The current year Winter Peak Load ERS amount escalated by the compound annual growth rate of the three Winter Peak Load ERS amounts preceding the current year.</td><td>The current year Summer Peak Load ERS amount escalated by the compound annual growth rate of the three Summer Peak Load ERS amounts preceding the current period.</td></tr>
<tr><td>Third Year (i = 3)</td><td>The second year Winter Peak Load ERS amount escalated by the compound annual growth rate of the three Winter Peak Load ERS amounts preceding the current year.</td><td>The second year Summer Peak Load ERS amount escalated by the compound annual growth rate of the three Summer Peak Load ERS amounts preceding the current year.</td></tr>
<tr><td>Years after Third Year (i > 3)</td><td>Equal to third year amount.</td><td>Equal to third year amount.</td></tr>
</table></td></tr>
<tr><td>CLR $_{s, i}$</td><td>MW</td><td><i>Amount of Controllable Load Resource</i>—Estimated amount of Controllable Load Resource that is available for Dispatch by ERCOT during the current year <i>i</i> for the Peak Load Season <i>s</i> not already included in LRRRS or LRNSRS. This value does not include Wholesale Storage Load (WSL).
<i>[NPRR863: Insert the definition above with the following upon system implementation:]</i>
<i>Amount of Controllable Load Resource</i>—Estimated amount of Controllable Load Resource that is available for Dispatch by ERCOT during the current year <i>i</i> for the Peak Load Season <i>s</i> not already included in LRRRS, LRECRS, or LRNSRS. This value does not include Wholesale Storage Load (WSL).</td></tr>
</table>

ENERGYEFF $_{s,\,i}$	MW	*Amount of Energy Efficiency Programs Procured*—Estimated amount of energy efficiency programs procured by Transmission and/or Distribution Service Providers (TDSPs) pursuant to P.U.C. SUBST. R. 25.181, Energy Efficiency Goal, for the Peak Load Season *s* for the year *i*. ERCOT may also consider any energy efficiency and/or Demand response initiatives reported by NOIEs.
i	None	Year.
s	None	Peak Load Season.

3.2.6.2.2 Total Capacity Estimate

(1) The total capacity estimate shall be determined based on the following equation:

$$\mathbf{TOTCAP}_{s,i} = \mathbf{INSTCAP}_{s,i} + \mathbf{PUNCAP}_{s,i} + \mathbf{WINDCAP}_{s,i,r} + \mathbf{HYDROCAP}_{s,i} + \mathbf{SOLARCAP}_{s,i} + \mathbf{RMRCAP}_{s,i} + \mathbf{DCTIECAP}_{s} + \mathbf{PLANDCTIECAP}_{s} + \mathbf{SWITCHCAP}_{s,i} + \mathbf{MOTHCAP}_{s,i} + \mathbf{PLANNON}_{s,i} + \mathbf{PLANIRR}_{s,i,r} - \mathbf{LTOUTAGE}_{s,i} - \mathbf{UNSWITCH}_{s,i} - \mathbf{RETCAP}_{s,i}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
TOTCAP $_{s,\,i}$	MW	*Total Capacity*—Estimated total capacity available during the Peak Load Season *s* for the year *i*.
INSTCAP $_{s,\,i}$	MW	*Seasonal Net Max Sustainable Rating*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each operating Generation Resource for the year *i* excluding WGRs, hydro Generation Resource capacity, solar unit capacity, Resources operating under RMR Agreements, and Generation Resources capable of "switching" from the ERCOT Region to a non-ERCOT Region.
PUNCAP $_{s,\,i}$	MW	*Private Use Network Capacity*—The forecasted generation capacity available to the ERCOT Transmission Grid, net of self-serve load, from Generation Resources and Settlement Only Generators (SOGs) in Private Use Networks for Peak Load Season *s* and year *i*. The capacity forecasts are developed as follows. First, a base capacity forecast, determined from Settlement data, is calculated as the average net generation capacity available to the ERCOT Transmission Grid during the 20 highest system-wide peak Load hours for each preceding three-year period for Peak Load Season *s* and year *i*. The base capacity forecast is then adjusted by adding the aggregated incremental forecasted annual changes in net generation capacity as of the start of the summer Peak Load Season *s* for forecast year *i* reported for Private Use Networks pursuant to Section 10.3.2.4, Reporting of Net Generation Capacity. This calculation is limited to Generation Resources and SOGs in Private Use Networks (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.

Variable	Unit	Definition
WINDPEAKPCT $_{s, r}$	%	*Seasonal Peak Average Wind Capacity as a Percent of Installed Capacity*—The average WGR capacity available for the summer and winter Peak Load Seasons *s* and region *r*, divided by the installed capacity for region *r*, expressed as a percentage. The Seasonal Peak Average, derived from Settlement data, is first calculated as the average capacity during the 20 highest system-wide peak Load hours for a given year's summer and winter Peak Load Seasons. The final value is the weighted average of the previous ten eligible years of Seasonal Peak Average values where each year is weighted by its installed capacity. Eligible years include 2009 through the most recent year for which COP data is available for the summer and winter Peak Load Seasons. If the number of eligible years is less than ten, the average shall be based on the number of eligible years available. This calculation is limited to WGRs (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
WINDCAP $_{s, i, r}$	MW	*Existing WGR Capacity*—The capacity available for all existing WGRs for the summer and winter Peak Load Seasons *s,* year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Peak Load Seasons *s* and region *r*.
HYDROCAP $_{s, i}$	MW	*Hydro Unit Capacity*—The average hydro Generation Resource capacity available, as determined from the COP, during the highest 20 peak Load hours for each preceding three-year period for Peak Load Season *s* and year *i*. This calculation is limited to hydro Generation Resources (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
SOLARPEAKPCT $_{s}$	%	*Seasonal Peak Average Solar Capacity as a Percent of Installed Capacity*—The average PVGR capacity available for the summer and winter Peak Load Seasons *s*, divided by the installed capacity, expressed as a percentage. The Seasonal Peak Average, derived from Settlement data, is first calculated as the average capacity during the 20 highest system-wide peak Load hours for a given year's summer and winter Peak Load Seasons. The final value is the weighted average of the previous three years of Seasonal Peak Average values where each year is weighted by its installed capacity. This calculation is limited to PVGRs (1) with a Resource Commissioning Date that occurs no later than the start of the most current Peak Load Season used for the calculation, and (2) that have not been permanently retired by the start of the most current Peak Load Season used for the calculation.
SOLARCAP $_{s, i}$	MW	*Existing PVGR Capacity*—The capacity available for all existing PVGRs for the summer and winter Peak Load Season *s* and year *i*, multiplied by SOLARPEAKPCT for summer and winter Peak Load Seasons *s.*
RMRCAP $_{s, i}$	MW	*Seasonal Net Max Sustainable Rating for Generation Resource providing RMR Service*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Generation Resource providing RMR Service for the year *i* until the approved exit strategy for the RMR Resource is expected to be completed.

Variable	**Unit**	**Definition**
DCTIEPEAKPCT $_s$	%	*Seasonal Peak Average Capacity for existing DC Tie Resources as a Percent of Installed DC Tie Capacity*—The average net emergency DC Tie imports for the summer and winter Peak Load Seasons *s*, divided by the total installed DC Tie capacity for Peak Load Seasons *s*, expressed as a percentage. The average net emergency DC Tie imports is calculated for the SCED intervals during which ERCOT declared an Energy Emergency Alert (EEA). This calculation is limited to the most recent single summer and winter Peak Load Seasons in which an EEA was declared. The total installed DC Tie capacity is the capacity amount at the start of the Peak Load Seasons used for calculating the net DC Tie imports.
DCTIECAP $_s$	MW	*Expected Existing DC Tie Capacity Available under Emergency Conditions*—DCTIEPEAKPCT $_s$ multiplied by the installed DC Tie capacity available for the summer and winter Peak Load Seasons *s*, adjusted for any known capacity transfer limitations.
PLANDCTIECAP $_s$	MW	*Expected Planned DC Tie Capacity Available under Emergency Conditions*—DCTIEPEAKPCT $_s$ multiplied by the maximum peak import capacity of planned DC Tie projects included in the most recent Steady State Working Group (SSWG) base cases, for the summer and winter Peak Load Seasons *s*. The import capacity may be adjusted to reflect known capacity transfer limitations indicated by transmission studies.
SWITCHCAP $_{s,\ i}$	MW	*Seasonal Net Max Sustainable Rating for Switchable Generation Resource*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Generation Resource for the year *i* that can electrically connect (i.e., "switch") from the ERCOT Region to another power region.
MOTHCAP $_{s,\ i}$	MW	*Seasonal Net Max Sustainable Rating for Mothballed Generation Resource*—The Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource Registration process for each Mothballed Generation Resource for the year *i* based on the lead time and probability information furnished by the owners of Mothballed Generation Resources pursuant to Section 3.14.1.9, Generation Resource Status Updates. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is greater than or equal to 50%, then use the Seasonal net max sustainable rating for the Peak Load Season *s* as reported in the approved Resource registration process for the Mothballed Generation Resource for the year *i*. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is less than 50%, then exclude that Resource from the Total Capacity Estimate.

Variable	Unit	Definition
PLANNON $_{s,\ i}$	MW	*New, non-IRR Generating Capacity*—The amount of new, non-IRR generating capacity available by July 1 and December 1 for the summer and winter Peak Load Seasons *s*, respectively, and year *i* that: (a) has a Texas Commission on Environmental Quality (TCEQ)-approved air permit, (b) has a federal Greenhouse Gas permit, if required, (c) has obtained water rights, contracts or groundwater supplies sufficient for the generation of electricity at the Resource, and (d) has a signed Standard Generation Interconnect Agreement (SGIA), or a public, financially-binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed; or for a Municipally Owned Utility (MOU) or Electric Cooperative (EC), a public commitment letter to construct a new Resource. New, non-IRR generating capacity is excluded if the Generation Interconnection or Change Request (GINR) project status in the online Resource Integration and Ongoing Operations (RIOO) interconnection services system is set to "Cancelled" or "Inactive" or if the Resource was previously mothballed or retired and does not have an owner that intends to operate it. For the purposes of this section, ownership of a mothballed or retired Resource for which a new generation interconnection is sought can only be satisfied by proof of site control as described in paragraph (1)(a), (b), or (d) of Planning Guide Section 5.3.2.1, Proof of Site Control.
PLANIRR $_{s,\ i,\ r}$	MW	*New IRR Capacity*—For new WGRs, the capacity available by July 1 and December 1 for the summer and winter Peak Load Seasons *s,* respectively, year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Load Season *s* and region *r*. For new PVGRs, the capacity available for the summer and winter Peak Load Seasons *s* and year *i*, multiplied by SOLARPEAKPCT for summer and winter Load Seasons *s*. New IRRs must have an SGIA or other public, financially binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed or, for a MOU or EC, a public commitment letter to construct a new IRR. New IRR capacity is excluded if the GINR project status in the online RIOO interconnection services system is set to "Cancelled," or "Inactive."
LTOUTAGE $_{s,\ i}$	MW	*Forced Outage Capacity Reported in a Notification of Suspension of Operations*—For non-IRRs whose operation has been suspended due to a Forced Outage as reported in a Notification of Suspension of Operations (NSO), the sum of Seasonal net max sustainable ratings for Peak Load Seasons *s* for year *i*, as reported in the NSO forms. For IRRs, use the PLANIRR $_{s,\ i,\ r}$ calculated for each IRR.
UNSWITCH $_{s,\ i}$	MW	*Capacity of Unavailable Switchable Generation Resource*—The amount of capacity reported by the owners of a switchable Generation Resource that will be unavailable to ERCOT during the Peak Load Season *s* and year *i* pursuant to paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information.
RETCAP $_{s,\ i}$	MW	*Capacity Pending Retirement*—The amount of capacity in Peak Load Season *s* of year *i* that is pending retirement based on information submitted on an NSO form (Section 22, Attachment E, Notification of Suspension of Operations) pursuant to Section 3.14.1.11, Budgeting Eligible Costs, but is under review by ERCOT pursuant to Section 3.14.1.2, ERCOT Evaluation Process, that has not otherwise been considered in any of the above defined categories. For Generation Resources and SOGs within Private Use Networks, the retired capacity amount is the peak average capacity contribution included in PUNCAP. For reporting of individual Generation Resources and SOGs in the Report on the Capacity, Demand and Reserves in the ERCOT Region, only the summer net max sustainable rating included in the NSO shall be disclosed.

Variable	Unit	Definition
i	None	Year.
s	None	Summer and winter Peak Load Seasons for year i.
r	None	Coastal, Panhandle, and Other wind regions. WGRs are classified into regions based on the county that contains their Point of Interconnection Bus (POIB). The Coastal region is defined as the following counties: Aransas, Brazoria, Calhoun, Cameron, Kenedy, Kleberg, Matagorda, Nueces, Refugio, San Patricio, and Willacy. The Panhandle region is defined as the following counties: Armstrong, Bailey, Briscoe, Carson, Castro, Childress, Cochran, Collingsworth, Crosby, Dallam, Deaf Smith, Dickens, Donley, Floyd, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Lamb, Lipscomb, Lubbock, Moore, Motley, Ochiltree, Oldham, Parmer, Potter, Randall, Roberts, Sherman, Swisher, and Wheeler. The Other region consists of all other counties in the ERCOT Region.

3.3 Management of Changes to ERCOT Transmission Grid

(1) Additions and changes to the ERCOT System must be coordinated with ERCOT to accurately represent the ERCOT Transmission Grid.

3.3.1 ERCOT Approval of New or Relocated Facilities

(1) Before energizing and placing into service any new or relocated facility connected to the ERCOT Transmission Grid, a Transmission Service Provider (TSP), Qualified Scheduling Entity (QSE), or Resource Entity shall enter appropriate information in the Outage Scheduler and coordinate with, and receive written notice of approval from, ERCOT.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Before energizing and placing into service any new or relocated facility connected to the ERCOT Transmission Grid, a Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), Qualified Scheduling Entity (QSE), or Resource Entity shall enter appropriate information in the Outage Scheduler and coordinate with, and receive written notice of approval from, ERCOT.

3.3.2 Types of Work Requiring ERCOT Approval

(1) Each TSP, QSE and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid:

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP, DCTO, QSE, and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid:

(a) Transmission lines;

(b) Equipment including circuit breakers, transformers, disconnects, and reactive devices;

(c) Resource interconnections; and

(d) Protection and control schemes, including changes to Remedial Action Plans (RAPs), Supervisory Control and Data Acquisition (SCADA) systems, Energy Management Systems (EMSs), Automatic Generation Control (AGC), Remedial Action Schemes (RASs), or Automatic Mitigation Plans (AMPs).

3.3.2.1 Information to Be Provided to ERCOT

(1) The energization or removal of a Transmission Facility or Generation Resource in the Network Operations Model requires an entry into the Outage Scheduler by a TSP or Resource Entity. For TSP requests, the TSPs shall enter such requests in the Outage Scheduler. For Resource Entity requests, the Resource Entity shall enter such requests in the Outage Scheduler. If any changes in system topology or telemetry are expected, then the TSP or Resource Entity shall notify ERCOT in accordance with the schedule in Section 3.3.1, ERCOT Approval of New or Relocated Facilities. Information submitted pursuant to this subsection for Transmission Facilities within a Private Use Network shall not be publicly posted.

[NPRR857 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities for NPRR857; and upon system implementation for NPRR1014:]

(1) The energization or removal of a Transmission Facility, Generation Resource, or Energy Storage Resource (ESR) in the Network Operations Model requires an entry into the Outage Scheduler by a TSP, DCTO, or Resource Entity. For any TSP or DCTO request, the TSP or DCTO shall enter the request in the Outage Scheduler. For any Resource Entity request, the Resource Entity shall enter the request in the Outage Scheduler. If any changes in system topology or telemetry are expected, then the TSP, DCTO, or Resource Entity shall notify ERCOT in accordance with the schedule in Section 3.3.1, ERCOT Approval of New or Relocated Facilities. Information submitted pursuant to this subsection for Transmission Facilities within a Private Use Network shall not be publicly posted.

(2) If a Resource Entity within a Private Use Network is adding or removing a Transmission Facility at the Point of Interconnection (POI), it shall inform and determine with ERCOT whether any corresponding Network Operations Model updates are necessary. If ERCOT and the Resource Entity determine that updates are needed, the process set forth in paragraph (1) above shall be used to incorporate the update into the Network Operations Model. Information submitted pursuant to paragraph (1) above shall not be publicly posted.

(3) TSPs and Resource Entities shall submit any changes in system topology or telemetry in accordance with the Network Operations Model Change Request (NOMCR) process or other ERCOT-prescribed process applicable to Resource Entities and according to the requirements of Section 3.10.1, Time Line for Network Operations Model Changes. The submittal shall include the following:

(a) Proposed energize date;

(b) TSPs or Resource Entities performing work;

(c) TSPs or Resource Entities responsible for rating affected Transmission Element(s);

(d) For Resource Entities, data and information required by Section 16.5, Registration of a Resource Entity;

(e) Station identification code;

(f) Identification of existing Transmission Facilities involved and new Transmission Facilities (if any) being added or existing Transmission Facilities being permanently removed from service;

(g) Ratings of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(h) Outages required (clearly identify each Outage if multiple Outages are required), including sequence of Outage and estimate of Outage duration;

(i) General statement of work to be completed with intermediate progress dates and events identified;

(j) SCADA modification work, including descriptions of the telemetry points or changes to existing telemetry, providing information on equipment being installed, changed, or monitored;

(k) Additional data determined by ERCOT and TSPs, or Resource Entities as needed to complete the ERCOT model representation of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(l) Statement of completion, including:

    (i) Statement to be made at the completion of each intermediate stage of project; and

    (ii) Statement to be made at completion of total project.

(m) Drawings, including:

    (i) Existing status;

    (ii) Each intermediate stage; and

    (iii) Proposed final configuration.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) Each TSP, DCTO, and Resource Entity shall submit any changes in system topology or telemetry in accordance with the Network Operations Model Change Request (NOMCR) process or other ERCOT-prescribed process applicable to Resource Entities

and according to the requirements of Section 3.10.1, Time Line for Network Operations Model Changes. The submittal shall include the following:

(a) Proposed energize date;

(b) TSPs, DCTOs, or Resource Entities performing work;

(c) TSPs, DCTOs, or Resource Entities responsible for rating affected Transmission Element(s);

(d) For Resource Entities, data and information required by Section 16.5, Registration of a Resource Entity;

(e) Station identification code;

(f) Identification of existing Transmission Facilities involved and new Transmission Facilities (if any) being added or existing Transmission Facilities being permanently removed from service;

(g) Ratings of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(h) Outages required (clearly identify each Outage if multiple Outages are required), including sequence of Outage and estimate of Outage duration;

(i) General statement of work to be completed with intermediate progress dates and events identified;

(j) SCADA modification work, including descriptions of the telemetry points or changes to existing telemetry, providing information on equipment being installed, changed, or monitored;

(k) Additional data determined by ERCOT, TSPs, DCTOs, or Resource Entities as needed to complete the ERCOT model representation of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(l) Statement of completion, including:

    (i) Statement to be made at the completion of each intermediate stage of project; and

    (ii) Statement to be made at completion of total project.

(m) Drawings, including:

    (i) Existing status;

    (ii) Each intermediate stage; and

(iii) Proposed final configuration.

3.3.2.2 Record of Approved Work

(1) ERCOT shall maintain a record of all work approved in accordance with Section 3.3, Management of Changes to ERCOT Transmission Grid, and shall publish, and update monthly, information on the MIS Secure Area regarding each new Transmission Element to be installed on the ERCOT Transmission Grid.

3.4 Load Zones

(1) ERCOT shall assign every power flow bus to a Load Zone for Day-Ahead Market (DAM) and Congestion Revenue Right (CRR) Settlement purposes. ERCOT shall calculate a Settlement Point Price for each Load Zone using the Load-weighted aggregated Shift Factors of the applicable energized power flow buses for each constraint. The Load-weighting must be determined using the Load distribution factors.

(2) ERCOT shall assign every Electrical Bus to a Load Zone for Real-Time Market (RTM) Settlement purposes. ERCOT shall calculate a Settlement Point Price for each Load Zone as the Load-weighted average of the Locational Marginal Prices (LMPs) at all Electrical Buses assigned to that Load Zone. The Load-weighting must be determined using the Load, if any, from the State Estimator at each Electrical Bus.

3.4.1 Load Zone Types

(1) The Load Zone types are:

(a) The Competitive Load Zones;

(b) The Non-Opt-In Entity (NOIE) Load Zones created pursuant to Section 3.4.3, NOIE Load Zones; and

(c) The Direct Current Tie (DC Tie) Load Zones as defined in Section 3.4.4, DC Tie Load Zones.

(2) The Competitive Load Zones are the four zones in effect during the 2003 ERCOT market unless they are changed pursuant to Section 3.4.2, Load Zone Modifications, less any Electrical Buses that are assigned to a NOIE Load Zone or a DC Tie Load Zone.

3.4.2 Load Zone Modifications

(1) Competitive Load Zones and NOIE Load Zones may be added, deleted, or changed, only when approved by the ERCOT Board, with the exception of paragraph (1)(c) of Section 3.4.3, NOIE Load Zones. Approved additions, deletions, or changes go into effect 48

months after the end of the month in which the addition, deletion, or change was approved, with the exception of paragraph (3) below. DC Tie Load Zones are not subject to these requirements.

(2) The addition of Load that is new to the ERCOT System to an existing Load Zone does not constitute a change to a Load Zone under this section. This provision includes the transfer of existing Load from a non-ERCOT Control Area into a Load Zone in the ERCOT System. Adding Load that is new to the ERCOT System to an existing Load Zone does not require ERCOT Board approval, and no notice period is required prior to adding such Load to an existing Load Zone.

(3) A NOIE that was included in the establishment of an automatic pre-assigned NOIE Load Zone under paragraph (1)(c) of Section 3.4.3 may elect to be assigned to an appropriate Competitive Load Zone after giving notice of termination of its power supply arrangement if a request to be assigned to a Competitive Load Zone was given to ERCOT at least 90 days prior to the start of the Pre-Assigned Congestion Revenue Right (PCRR) nomination window for the effective year of the Load Zone change. The move to a Competitive Load Zone requires ERCOT Board approval and shall be effective no sooner than the first day of the PCRR Nomination Year.

3.4.3 NOIE Load Zones

(1) The descriptions and conditions set forth below apply to Load Zones established by NOIEs:

(a) There are four NOIE Load Zones that were approved prior to the Texas Nodal Market Implementation Date: Austin Energy, City Public Service, Rayburn Country Electric Cooperative, and Lower Colorado River Authority (LCRA);

(b) Any costs allocated based upon a zonal Load Ratio Share (LRS) must be allocated using “Cost-Allocation Load Zones,” which are the four Load Zones in effect during the 2003 ERCOT market unless they are changed pursuant to Section 3.4.2, Load Zone Modifications. For these allocation purposes, any NOIE Load Zone is considered to be located entirely within the 2003 ERCOT Congestion Management Zone (CMZ) that represented the largest Load for that NOIE or group of NOIEs in 2003;

(c) A separate NOIE Load Zone is made up of a group of NOIEs that are parties to the same pre-1999 power supply arrangements and that had an overall 2003 peak Load in excess of 2,300 MW. A NOIE that is a member of this separate NOIE Load Zone and that has given notice of termination of its pre-1999 power supply arrangement may elect to be assigned to an appropriate Competitive Load Zone. Such an election shall be subject to the approval process in Section 3.4.2;

(d) NOIEs may participate in only one NOIE Load Zone, and all Loads served by that NOIE must be contained within that Load Zone;

(e) Except as specified otherwise in this subsection, Load Zones established by NOIEs will be treated the same as other Load Zones, including a 48-month notice requirement for ERCOT Board approval of any changes to Load Zones. However, the addition of Load that is new to the ERCOT System, including the transfer of existing Load from a non-ERCOT Control Area, into an existing NOIE Load Zone is not a change to a Load Zone under these Protocols; and

(f) Four years after a NOIE offers its Customers retail choice, the NOIE's Load must be merged into the appropriate Competitive Load Zone(s). For a Load Zone that is an aggregation of NOIE systems of which less than all of the NOIEs opt into Customer Choice, each remaining NOIE in that NOIE Load Zone may choose to have its Load merged into the appropriate Competitive Load Zone(s) under the same four-year time frame.

3.4.4 DC Tie Load Zones

(1) A DC Tie Load Zone contains only the Electrical Bus in the ERCOT Transmission Grid that connects the DC Tie and is used in the settlement of the DC Tie Load in that zone.

3.4.5 Additional Load Buses

(1) ERCOT shall assign new Electrical Buses to a Load Zone and Cost Allocation Zone in accordance with the following rules; changes are effective immediately:

(a) For each new Electrical Bus serving Load of a NOIE that is a part of a NOIE Load Zone, the new Electrical Bus will be assigned to that NOIE Load Zone;

(b) For each new Electrical Bus not covered in paragraph (a) above, connected via Transmission Facilities to Electrical Buses all located within the same Competitive Load Zone, the new Electrical Bus will be assigned to that Competitive Load Zone;

(c) For each new Electrical Bus not covered in paragraphs (a) or (b) above, ERCOT shall simulate LMPs for the annual peak hour of the system with the new Electrical Bus incorporated into the model. ERCOT shall assign that new Electrical Bus to the Competitive Load Zone with the closest matching zonal Settlement Point Price to the new Electrical Bus's LMP;

(d) For each new Electrical Bus covered in paragraph (a) above and connected via Transmission Facilities to Electrical Buses all located within the same Cost Allocation Zone, then the new Electrical Bus will be assigned to that Cost Allocation Zone;

(e) For each new Electrical Bus covered in paragraph (a) above and not covered in paragraph (d) above, ERCOT shall simulate LMPs for the annual peak hour of the system with the new Electrical Bus incorporated into the model. ERCOT shall assign each new Electrical Bus associated with a NOIE that is a part of a NOIE

Load Zone to the Cost Allocation Zone with the closest matching zonal Settlement Point Price to the new Electrical Bus's LMP.

(f) For each new Electrical Bus not covered in paragraph (a), the new Electrical Bus is assigned to the same Cost Allocation Zone as its designated Load Zone;

3.5 Hubs

3.5.1 Process for Defining Hubs

(1) Hubs settled through ERCOT may only be created by an amendment to Section 3.5.2, Hub Definitions. Hubs are made up of one or more Electrical Buses. ERCOT shall post the list of Electrical Buses (including their names) that are part of a Hub on the ERCOT website. A Hub, once defined, may not be modified except as explicitly described in the definition of that Hub.

(2) When any Electrical Bus within a Hub Bus is added to the Network Operations Model or the Congestion Revenue Right (CRR) Network Model through changes to the Network Operations Model or CRR Network Model, ERCOT shall provide notice to all Market Participants as soon as practicable and include that Electrical Bus in the Hub Bus price calculation.

(3) When any Electrical Bus within a Hub Bus is disconnected from the Network Operations Model or the CRR Network Model through operations changes in transmission topology temporarily, ERCOT shall provide notice to all Market Participants as soon as practicable and exclude that Electrical Bus from the Hub Bus price calculation.

(4) In the event of a permanent change that removes the Hub Bus from the ERCOT Transmission Grid, ERCOT shall file a Nodal Protocol Revision Request (NPRR) to revise the appropriate Hub definition.

(5) If a Transmission Service Provider (TSP) or ERCOT plans a nomenclature change in the Network Operations Model or the CRR Network Model, ERCOT shall file a NPRR to include the nomenclature change in the Hub Bus definitions before implementing the name change to either the Network Operations Model or the CRR Network Model.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) If a Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), or ERCOT plans a nomenclature change in the Network Operations Model or the CRR

Network Model, ERCOT shall file a NPRR to include the nomenclature change in the Hub Bus definitions before implementing the name change to either the Network Operations Model or the CRR Network Model.

3.5.2 Hub Definitions

3.5.2.1 North 345 kV Hub (North 345)

(1) The North 345 kV Hub is composed of the following Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	ANASW	345	NORTH
2	CN345	345	NORTH
3	WLSH	345	NORTH
4	FMRVL	345	NORTH
5	LPCCS	345	NORTH
6	MNSES	345	NORTH
7	PRSSW	345	NORTH
8	SSPSW	345	NORTH
9	VLSES	345	NORTH
10	ALNSW	345	NORTH
11	ALLNC	345	NORTH
12	BNDVS	345	NORTH
13	BNBSW	345	NORTH
14	BBSES	345	NORTH
15	BOSQUESW	345	NORTH
16	CDHSW	345	NORTH
17	CNTRY	345	NORTH
18	CRLNW	345	NORTH
19	CMNSW	345	NORTH
20	CNRSW	345	NORTH
21	CRTLD	345	NORTH
22	DCSES	345	NORTH
23	EMSES	345	NORTH
24	ELKTN	345	NORTH
25	ELMOT	345	NORTH
26	EVRSW	345	NORTH
27	KWASS	345	NORTH
28	FGRSW	345	NORTH
29	FORSW	345	NORTH
30	FRNYPP	345	NORTH
31	GIBCRK	345	NORTH

	ERCOT Operations		
No.	Hub Bus	kV	Hub
32	HKBRY	345	NORTH
33	VLYRN	345	NORTH
34	JEWET	345	NORTH
35	KNEDL	345	NORTH
36	KLNSW	345	NORTH
37	LCSES	345	NORTH
38	LIGSW	345	NORTH
39	LEG	345	NORTH
40	LFKSW	345	NORTH
41	LWSSW	345	NORTH
42	MLSES	345	NORTH
43	MCCREE	345	NORTH
44	MDANP	345	NORTH
45	ENTPR	345	NORTH
46	NCDSE	345	NORTH
47	NORSW	345	NORTH
48	NUCOR	345	NORTH
49	PKRSW	345	NORTH
50	KMCHI	345	NORTH
51	PTENN	345	NORTH
52	RENSW	345	NORTH
53	RCHBR	345	NORTH
54	RNKSW	345	NORTH
55	RKCRK	345	NORTH
56	RYSSW	345	NORTH
57	SGVSW	345	NORTH
58	SHBSW	345	NORTH
59	SHRSW	345	NORTH
60	SCSES	345	NORTH
61	SYCRK	345	NORTH
62	THSES	345	NORTH
63	TMPSW	345	NORTH
64	TNP_ONE	345	NORTH
65	TRCNR	345	NORTH
66	TRSES	345	NORTH
67	TOKSW	345	NORTH
68	VENSW	345	NORTH
69	WLVEE	345	NORTH
70	W_DENT	345	NORTH
71	WTRML	345	NORTH
72	WCSWS	345	NORTH
73	WEBBS	345	NORTH

	ERCOT Operations		
No.	Hub Bus	kV	Hub
74	WHTNY	345	NORTH
75	WCPP	345	NORTH

(2) The North 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the Day-Ahead Market (DAM) in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{North345} = \textbf{DASL} - \sum_{c}(\textbf{DAHUBSF}_{North345,\,c} * \textbf{DASP}_{c}),\ \textbf{if HBBC}_{North345} \neq \textbf{0}$$

$$\textbf{DASPP}_{North345} = \textbf{DASPP}_{ERCOT345Bus},\ \textbf{if HBBC}_{North345} = \textbf{0}$$

Where:

$$\text{DAHUBSF}_{North345,\,c} = \sum_{hb}(\text{HUBDF}_{hb,\,North345,\,c} * \text{DAHBSF}_{hb,\,North345,\,c})$$

$$\text{DAHBSF}_{hb,\,North345,\,c} = \sum_{pb}(\text{HBDF}_{pb,\,hb,\,North345,\,c} * \text{DASF}_{pb,\,hb,\,North345,\,c})$$

$$\text{HUBDF}_{hb,\,North345,\,c} = \text{IF}(\text{HB}_{North345,\,c}=0,\ 0,\ 1\ /\ \text{HB}_{North345,\,c})$$

$$\text{HBDF}_{pb,\,hb,\,North345,\,c} = \text{IF}(\text{PB}_{hb,\,North345,\,c}=0,\ 0,\ 1\ /\ \text{PB}_{hb,\,North345,\,c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{DASPP}_{North345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP_{c}	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{North345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{hb,North345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{pb,hb,North345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.

Variable	Unit	Definition
$\text{HUBDF}_{\textit{hb, North345,c}}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{\textit{pb, hb, North345,c}}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{\textit{hb, North345,c}}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$\text{HBBC}_{\textit{North345}}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$\text{HB}_{\textit{North345,c}}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\textit{North345}} = \mathbf{Max\ [-\$251, (RTRSVPOR + RTRDP + \sum_{hb} (HUBDF}_{\textit{hb, North345}} \mathbf{* (\sum_{y} (RTHBP}_{\textit{hb, North345, y}} \mathbf{* TLMP}_{y}\mathbf{) / (\sum_{y} TLMP}_{y}\mathbf{))))], if\ HB}_{\textit{North345}}\mathbf{\neq 0}$$

$$\mathbf{RTSPP}_{\mathbf{North345}} = \mathbf{RTSPP}_{\mathbf{ERCOT345Bus}}\mathbf{, if\ HB}_{\mathbf{North345}}\mathbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

$$\text{RTHBP}_{hb,\ North345,\ y} = \sum_{b} (\text{HBDF}_{b,\ hb,\ North345} * \text{RTLMP}_{b,\ hb,\ North345,\ y})$$

$$\text{HUBDF}_{hb,\ North345} = \text{IF}(\text{HB}_{North345}=0, 0, 1 / \text{HB}_{North345})$$

$$\text{HBDF}_{b,\ hb,\ North345} = \text{IF}(\text{B}_{hb,\ North345}=0,\ 0,\ 1\ /\ \text{B}_{hb,\ North345})$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{North345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$\text{RTHBP}_{hb,\ North345,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per Security-Constrained Economic Dispatch (SCED) interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time price adder for On-Line Reserves for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTLMP}_{b,\ hb,\ North345,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
$\text{HUBDF}_{hb,\ North345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$\text{HBDF}_{b,\ hb,\ North345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$\text{B}_{hb,\ North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$\text{HB}_{North345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{North345} = \textbf{Max [-\$251, (RTRDP + } \sum_{y} \textbf{(HUBLMP}_{North345,\,y} \textbf{ * RNWF}_{y}\textbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{North345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA_{y}	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.*
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{HUBLMP}_{North345,\,y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.2 South 345 kV Hub (South 345)

(1) The South 345 kV Hub is composed of the following Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	AUSTRO	345	SOUTH
2	BLESSING	345	SOUTH
3	CAGNON	345	SOUTH
4	COLETO	345	SOUTH
5	CLEASP	345	SOUTH

	ERCOT Operations		
No.	Hub Bus	kV	Hub
6	NEDIN	345	SOUTH
7	FAYETT	345	SOUTH
8	FPPYD1	345	SOUTH
9	FPPYD2	345	SOUTH
10	GARFIE	345	SOUTH
11	GUADG	345	SOUTH
12	HAYSEN	345	SOUTH
13	HILLCTRY	345	SOUTH
14	HOLMAN	345	SOUTH
15	KENDAL	345	SOUTH
16	LA_PALMA	345	SOUTH
17	LON_HILL	345	SOUTH
18	LOSTPI	345	SOUTH
19	LYTTON_S	345	SOUTH
20	MARION	345	SOUTH
21	PAWNEE	345	SOUTH
22	RIOHONDO	345	SOUTH
23	RIONOG	345	SOUTH
24	SALEM	345	SOUTH
25	SANMIGL	345	SOUTH
26	SKYLINE	345	SOUTH
27	STP	345	SOUTH
28	CALAVERS	345	SOUTH
29	BRAUNIG	345	SOUTH
30	WHITE_PT	345	SOUTH
31	ZORN	345	SOUTH

(2) The South 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\,South345} = \mathbf{DASL} - \sum_{c}(\mathbf{DAHUBSF}_{\,South345,\,c} * \mathbf{DASP}_{\,c}),\ \text{if}\ \mathbf{HBBC}_{\,South345} \neq 0$$

$$\mathbf{DASPP}_{\,South345} = \mathbf{DASPP}_{\,ERCOT345Bus},\ \text{if}\ \mathbf{HBBC}_{\,South345} = 0$$

Where:

$$\text{DAHUBSF}_{South345,\,c} = \sum_{hb}(\text{HUBDF}_{hb,\,South345,\,c} * \text{DAHBSF}_{hb,\,South345,\,c})$$

$$\text{DAHBSF}_{hb,\ South345,\ c} \quad = \quad \sum_{pb}(\text{HBDF}_{pb,\ hb,\ South345,\ c} * \text{DASF}_{pb,\ hb,\ South345,\ c})$$

$$\text{HUBDF}_{hb,\ South345,\ c} \quad = \quad \text{IF}(\text{HB}_{South345,\ c}{=}0,\ 0,\ 1\ /\ \text{HB}_{South345,\ c})$$

$$\text{HBDF}_{pb,\ hb,\ South345,\ c} \quad = \quad \text{IF}(\text{PB}_{hb,\ South345,\ c}{=}0,\ 0,\ 1\ /\ \text{PB}_{hb,\ South345,\ c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DASPP $_{South345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{South345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
DAHBSF $_{hb,South345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
DASF $_{pb,hb,South345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
HUBDF $_{hb,\ South345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
HBDF $_{pb,\ hb,\ South345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
PB $_{hb,\ South345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
HBBC $_{South345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
HB $_{South345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{\textbf{South345}} \quad = \quad \textbf{Max [-\$251, (RTRSVPOR + RTRDP +}$$

$$\sum_{hb} (\mathbf{HUBDF}_{hb,\,South345} * (\sum_{y} (\mathbf{RTHBP}_{hb,\,South345,\,y} * \mathbf{TLMP}_{y}) / (\sum_{y} \mathbf{TLMP}_{y}))))], \text{ if } \mathbf{HB}_{South345} \neq 0$$

$$\mathbf{RTSPP}_{South345} = \mathbf{RTSPP}_{ERCOT345Bus}, \text{ if } \mathbf{HB}_{South345} = 0$$

Where:

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

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

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

$$RTHBP_{hb,\,South345,\,y} = \sum_{b} (HBDF_{b,\,hb,\,South345} * RTLMP_{b,\,hb,\,South345,\,y})$$

$$HUBDF_{hb,\,South345} = IF(HB_{South345}=0, 0, 1 / HB_{South345})$$

$$HBDF_{b,\,hb,\,South345} = IF(B_{hb,\,South345}=0, 0, 1 / B_{hb,\,South345})$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{South345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$RTHBP_{hb,\,South345,\,y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
$RTORPA_{y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$RTORDPA_{y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* –The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RTLMP_{b,\,hb,\,South345,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.

HUBDF $_{hb,\ South345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b,\ hb,\ South345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
B $_{hb,\ South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB $_{South345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{South345} = \mathbf{Max\ [-\$251,\ (RTRDP +} \sum_{y} \mathbf{(HUBLMP}_{South345,\ y} \mathbf{\ *\ RNWF}_{y}\mathbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{ RNWF}_{y} \text{ * RTRDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP $_{South345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA $_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* –The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
HUBLMP $_{South345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.

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

3.5.2.3 Houston 345 kV Hub (Houston 345)

(1) The Houston 345 kV Hub is composed of the following listed Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	ADK	345	HOUSTON
2	BI	345	HOUSTON
3	CBY	345	HOUSTON
4	CTR	345	HOUSTON
5	CHB	345	HOUSTON
6	DPW	345	HOUSTON
7	DOW	345	HOUSTON
8	RNS	345	HOUSTON
9	GBY	345	HOUSTON
10	JN	345	HOUSTON
11	KG	345	HOUSTON
12	KDL	345	HOUSTON
13	NB	345	HOUSTON
14	OB	345	HOUSTON
15	PHR	345	HOUSTON
16	SDN	345	HOUSTON
17	SMITHERS	345	HOUSTON
18	THW	345	HOUSTON
19	WAP	345	HOUSTON
20	WO	345	HOUSTON

(2) The Houston 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{Houston345} = \mathbf{DASL} - \sum_{c}(\mathbf{DAHUBSF}_{Houston345,\,c} * \mathbf{DASP}_{c}), \text{ if } \mathbf{HBBC}_{Houston345} \neq 0$$

$$\mathbf{DASPP}_{Houston345} = \mathbf{DASPP}_{ERCOT345Bus}, \text{ if } \mathbf{HBBC}_{Houston345} = 0$$

Where:

$$\text{DAHUBSF}_{\textit{Houston345, c}} = \sum_{hb}(\text{HUBDF}_{\textit{hb, Houston345, c}} * \text{DAHBSF}_{\textit{hb, Houston345, c}})$$

$$\text{DAHBSF}_{\textit{hb, Houston345, c}} = \sum_{pb}(\text{HBDF}_{\textit{pb, hb, Houston345, c}} * \text{DASF}_{\textit{pb, hb, Houston345, c}})$$

$$\text{HUBDF}_{\textit{hb, Houston345, c}} = \text{IF}(\text{HB}_{\textit{Houston345, c}}{=}0,\ 0,\ 1\ /\ \text{HB}_{\textit{Houston345, c}})$$

$$\text{HBDF}_{\textit{pb, hb, Houston345, c}} = \text{IF}(\text{PB}_{\textit{hb, Houston345, c}}{=}0,\ 0,\ 1\ /\ \text{PB}_{\textit{hb, Houston345, c}})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{\textit{Houston345}}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP_{c}	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{\textit{Houston345,c}}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{\textit{hb,Houston345,c}}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{\textit{pb,hb,Houston345,c}}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HUBDF}_{\textit{hb, Houston345,c}}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{\textit{pb, hb, Houston345,c}}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{\textit{hb, Houston345,c}}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$\text{HBBC}_{\textit{Houston345}}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$\text{HB}_{\textit{Houston345,c}}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\textit{\textbf{Houston345}}} = \mathbf{Max\ [-\$251,\ (RTRSVPOR + RTRDP +}$$

$$\sum_{hb} (\mathbf{HUBDF}_{\mathit{hb, Houston345}} * (\sum_{y} (\mathbf{RTHBP}_{\mathit{hb, Houston345, y}} *$$

$$\mathbf{TLMP}_{y}) / (\sum_{y} \mathbf{TLMP}_{y}))))], \textbf{ if } \mathbf{HB}_{\mathit{Houston345}} \neq 0$$

$$\mathbf{RTSPP}_{\mathbf{Houston345}} = \mathbf{RTSPP}_{\mathbf{ERCOT345Bus}}, \textbf{ if } \mathbf{HB}_{\mathbf{Houston345}} = 0$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

$$\text{RTHBP}_{hb,\ Houston345,\ y} = \sum_{b} (\text{HBDF}_{b,\ hb,\ Houston345} * \text{RTLMP}_{b,\ hb,\ Houston345,\ y})$$

$$\text{HUBDF}_{hb,\ Houston345} = \text{IF}(\text{HB}_{Houston345}=0, 0, 1 / \text{HB}_{Houston345})$$

$$\text{HBDF}_{b,\ hb,\ Houston345} = \text{IF}(\text{B}_{hb,\ Houston345}=0, 0, 1 / \text{B}_{hb,\ Houston345})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$\text{RTSPP}_{Houston345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$\text{RTHBP}_{hb,\ Houston345,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTLMP}_{b,\ hb,\ Houston345,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.

Variable	Unit	Description
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
HUBDF $_{hb,\ Houston345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b,\ hb,\ Houston345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
B $_{hb,\ Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB $_{Houston345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\ Houston345} = \mathbf{Max\ [-\$251,\ (RTRDP\ +\ \sum_{y}\ (HUBLMP}_{\ Houston345,\ y}\ \mathbf{*\ RNWF}_{\ y}\ \mathbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\ y} * \text{RTRDPA}_{\ y})$$

$$\text{RNWF}_{\ y} = \text{TLMP}_{\ y} \,/\, \sum_{y} \text{TLMP}_{\ y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP $_{Houston345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA $_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
HUBLMP $_{Houston345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.

RNWF_y	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP_y	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.4 West 345 kV Hub (West 345)

(1) The West 345 kV Hub is composed of the following listed Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	MULBERRY	345	WEST
2	BOMSW	345	WEST
3	OECCS	345	WEST
4	BITTCR	345	WEST
5	FSHSW	345	WEST
6	FLCNS	345	WEST
7	GRSES	345	WEST
8	JCKSW	345	WEST
9	MDLNE	345	WEST
10	MOSSW	345	WEST
11	MGSES	345	WEST
12	DCTM	345	WEST
13	ODEHV	345	WEST
14	OKLA	345	WEST
15	REDCREEK	345	WEST
16	SWESW	345	WEST
17	TWINBU	345	WEST

(2) The West 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{\textit{West345}} = \quad \textbf{DASL} - \sum_{c}(\textbf{DAHUBSF}_{\textit{West345, c}} * \textbf{DASP}_{c}), \text{ if } \textbf{HBBC}_{\textit{West345}} \neq 0$$

$$\textbf{DASPP}_{\textit{West345}} = \quad \textbf{DASPP}_{\textit{ERCOT345Bus}}, \text{ if } \textbf{HBBC}_{\textit{West345}} = 0$$

Where:

$$\text{DAHUBSF}_{\,West345,\,c} = \sum_{hb} (\text{HUBDF}_{\,hb,\,West345,\,c} * \text{DAHBSF}_{\,hb,\,West345,\,c})$$

$$\text{DAHBSF}_{\,hb,\,West345,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,West345,\,c} * \text{DASF}_{\,pb,\,hb,\,West345,\,c})$$

$$\text{HUBDF}_{\,hb,\,West345,\,c} = \text{IF}(\text{HB}_{\,West345,\,c}{=}0,\ 0,\ 1\ /\ \text{HB}_{\,West345,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,West345,\,c} = \text{IF}(\text{PB}_{\,hb,\,West345,\,c}{=}0,\ 0,\ 1\ /\ \text{PB}_{\,hb,\,West345,\,c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DASPP $_{West345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{West345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
DAHBSF $_{hb,West345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
DASF $_{pb,hb,West345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
HUBDF $_{hb,\ West345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
HBDF $_{pb,\ hb,\ West345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
PB $_{hb,\ West345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
HBBC $_{West345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
HB $_{West345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{West345}} = \mathbf{Max\ [-\$251,\ (RTRSVPOR + RTRDP + \sum_{hb} (HUBDF}_{\mathit{hb,\ West345}} \mathbf{*\ (\sum_{y} (RTHBP}_{\mathit{hb,\ West345,\ y}} \mathbf{*\ TLMP}_{\mathit{y}}\mathbf{)\ /\ (\sum_{y} TLMP}_{\mathit{y}}\mathbf{))))],\ if\ HB}_{\mathit{West345}}\mathbf{\neq 0}$$

$$\mathbf{RTSPP}_{\mathit{West345}} = \mathbf{RTSPP}_{\mathit{ERCOT345Bus}}\mathbf{,\ if\ HB}_{\mathit{West345}}\mathbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

$$\text{RTHBP}_{hb,\ West345,\ y} = \sum_{b} (\text{HBDF}_{b,\ hb,\ West345} * \text{RTLMP}_{b,\ hb,\ West345,\ y})$$

$$\text{HUBDF}_{hb,\ West345} = \text{IF}(\text{HB}_{West345}=0,\ 0,\ 1 / \text{HB}_{West345})$$

$$\text{HBDF}_{b,\ hb,\ West345} = \text{IF}(\text{B}_{hb,\ West345}=0,\ 0,\ 1 / \text{B}_{hb,\ West345})$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP $_{West345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA $_{y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA $_{y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
RTHBP $_{hb,\ West345,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.

Variable	Unit	Description
RTLMP $_{b,\ hb,\ West345,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
HUBDF $_{hb,\ West345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b,\ hb,\ West345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
B $_{hb,\ West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB $_{West345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation of NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\ West345} = \mathbf{Max\ [-\$251,\ (RTRDP + \sum_{y} (HUBLMP}_{\ West345,\ y} \mathbf{* RNWF}_{\ y}\mathbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\ y} * \text{RTRDPA}_{\ y})$$

$$\text{RNWF}_{\ y} = \text{TLMP}_{\ y} / \sum_{y} \text{TLMP}_{\ y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP $_{West345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA $_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.

HUBLMP $_{West345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval y.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval y within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval y within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.5 Panhandle 345 kV Hub (Pan 345)

(1) The Panhandle 345 kV Hub is composed of the following listed Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	ABERNATH	345	PAN
2	AJ_SWOPE	345	PAN
3	ALIBATES	345	PAN
4	CTT_CROS	345	PAN
5	CTT_GRAY	345	PAN
6	OGALLALA	345	PAN
7	RAILHEAD	345	PAN
8	TESLA	345	PAN
9	TULECNYN	345	PAN
10	W_CW_345	345	PAN
11	WHIT_RVR	345	PAN
12	WINDMILL	345	PAN

(2) The Panhandle 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\mathit{Pan345}} = \mathbf{DASL} - \sum_{c}(\mathbf{DAHUBSF}_{\mathit{Pan345,\ c}} * \mathbf{DASP}_{\mathit{c}}), \text{ if } \mathbf{HBBC}_{\mathit{Pan345}} \neq 0$$

$$\mathbf{DASPP}_{\mathit{Pan345}} = \mathbf{DASPP}_{\mathit{ERCOT345Bus}}, \text{ if } \mathbf{HBBC}_{\mathit{Pan345}} = 0$$

Where:

$$\text{DAHUBSF}_{\mathit{Pan345,\ c}} = \sum_{hb}(\text{HUBDF}_{\mathit{hb,\ Pan345,\ c}} * \text{DAHBSF}_{\mathit{hb,\ Pan345,\ c}})$$

$$\text{DAHBSF}_{hb,\ Pan345,\ c} = \sum_{pb}(\text{HBDF}_{pb,\ hb,\ Pan345,\ c} * \text{DASF}_{pb,\ hb,\ Pan345,\ c})$$

$$\text{HUBDF}_{hb,\ Pan345,\ c} = \text{IF}(\text{HB}_{Pan345,\ c}=0,\ 0,\ 1 / \text{HB}_{Pan345,\ c})$$

$$\text{HBDF}_{pb,\ hb,\ Pan345,\ c} = \text{IF}(\text{PB}_{hb,\ Pan345,\ c}=0,\ 0,\ 1 / \text{PB}_{hb,\ Pan345,\ c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DASPP $_{Pan345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{Pan345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
DAHBSF $_{hb,Pan345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
DASF $_{pb,hb,Pan345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
HUBDF $_{hb,\ Pan345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
HBDF $_{pb,\ hb,\ Pan345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
PB $_{hb,\ Pan345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
HBBC $_{Pan345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
HB $_{Pan345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{Pan345} = \textbf{Max [-\$251, (RTRSVPOR + RTRDP +}$$

$$\sum_{hb} (\mathbf{HUBDF}_{hb,\ Pan345} * (\sum_{y} (\mathbf{RTHBP}_{hb,\ Pan345,\ y} * \mathbf{TLMP}_{y}) / (\sum_{y} \mathbf{TLMP}_{y}))))], \textbf{ if } \mathbf{HB}_{Pan345} \neq \mathbf{0}$$

$$\mathbf{RTSPP}_{Pan345} = \mathbf{RTSPP}_{ERCOT345Bus}, \textbf{ if } \mathbf{HB}_{Pan345} = \mathbf{0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

$$\text{RTHBP}_{hb,\ Pan345,\ y} = \sum_{b} (\text{HBDF}_{b,\ hb,\ Pan345} * \text{RTLMP}_{b,\ hb,\ Pan345,\ y})$$

$$\text{HUBDF}_{hb,\ Pan345} = \text{IF}(\text{HB}_{Pan345}=0, 0, 1 / \text{HB}_{Pan345})$$

$$\text{HBDF}_{b,\ hb,\ Pan345} = \text{IF}(\text{B}_{hb,\ Pan345}=0, 0, 1 / \text{B}_{hb,\ Pan345})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTSPP $_{Pan345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA $_{y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA $_{y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
RTHBP $_{hb,\ Pan345,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
RTLMP $_{b,\ hb,\ Pan345,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the SCED interval *y*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.

Variable	**Unit**	**Description**
$HUBDF_{hb,\ Pan345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b,\ hb,\ Pan345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb,\ Pan345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB_{Pan345}	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{Pan345} = \mathbf{Max\ [-\$251,\ (RTRDP + \sum_{y} (HUBLMP}_{Pan345,\ y} \mathbf{*\ RNWF}_{y}\mathbf{))]}$$

Where:

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

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

The above variables are defined as follows:

Variable	**Unit**	**Description**
$RTSPP_{Pan345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$HUBLMP_{Pan345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.

TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

[NPRR941, NPRR1007, and NPRR1057: Insert applicable portions of Section 3.5.2.6 below upon system implementation for NPRR941 or NPRR1057; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; and renumber accordingly:]

3.5.2.6 Lower Rio Grande Valley Hub (LRGV 138/345)

(1) The Lower Rio Grande Valley Hub 138/345 kV Hub is composed of the following listed Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	AIRPORT	138	LRGV
2	ALBERTA	138	LRGV
3	BATES	138	LRGV
4	FRONTERA	138	LRGV
5	GARZA	138	LRGV
6	HARLNSW	138	LRGV
7	HEC	138	LRGV
8	KEY_SW	138	LRGV
9	LA_PALMA_345	345	LRGV
10	LA_PALMA_138	138	LRGV
11	LASPULGA	138	LRGV
12	LISTON	138	LRGV
13	LOMA_ALT	138	LRGV
14	MARCONI	138	LRGV
15	MILHWY	138	LRGV
16	MILITARY	138	LRGV
17	MV_WEDN4	138	LRGV
18	N_MCALLN	138	LRGV
19	NEDIN_345	345	LRGV
20	NEDIN_138	138	LRGV
21	OLEANDER	138	LRGV
22	P_ISABEL	138	LRGV
23	PALMHRTP	138	LRGV
24	PALMITO_345	345	LRGV

25	PALMITO_138	138	LRGV
26	PAREDES	138	LRGV
27	PHARMVEC	138	LRGV
28	PHARR	138	LRGV
29	PRICE_RD	138	LRGV
30	RAILROAD	138	LRGV
31	RAYMND2	138	LRGV
32	REDTAP	138	LRGV
33	RIO_GRAN	138	LRGV
34	RIOHONDO_345	345	LRGV
35	RIOHONDO_138	138	LRGV
36	ROMA_SW	138	LRGV
37	S_MCALLN	138	LRGV
38	SCARBIDE	138	LRGV
39	SILASRAY	138	LRGV
40	STEWART	138	LRGV
41	WESLACO	138	LRGV

(2) The Lower Rio Grande Valley 138/345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\mathit{LRGV\ 138/345}} = \mathbf{DASL} - \sum_{c} (\mathbf{DAHUBSF}_{\mathit{LRGV\ 138/345,\ c}} * \mathbf{DASP}_{\mathit{c}}), \text{ if } \mathbf{HBBC}_{\mathit{LRGV138/345}} \neq 0$$

$$\mathbf{DASPP}_{\mathit{LRGV138/345}} = \mathbf{DASPP}_{\mathit{ERCOT345Bus}}, \text{ if } \mathbf{HBBC}_{\mathit{LRGV138/345}} = 0$$

Where:

$$\text{DAHUBSF}_{LRGV138/345,\ c} = \sum_{hb} (\text{HUBDF}_{hb,\ LRGV138/345,\ c} * \text{DAHBSF}_{hb,\ LRGV138/345,\ c})$$

$$\text{DAHBSF}_{hb,\ LRGV138/345,\ c} = \sum_{pb} (\text{HBDF}_{pb,\ hb,\ LRGV138/345,\ c} * \text{DASF}_{pb,\ hb,\ LRGV138/345,\ c})$$

$$\text{HUBDF}_{hb,\ LRGV138/345,\ c} = \text{IF}(\text{HB}_{LRGV138/345,\ c}=0, 0, 1 / \text{HB}_{LRGV138/345,\ c})$$

$$\text{HBDF}_{pb,\, hb,\, LRGV138/345,\, c} = \text{IF}(\text{PB}_{hb,\, LRGV138/345,\, c}=0,\ 0,\ 1\ /\ \text{PB}_{hb,\, LRGV138/345,\, c})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{LRGV138/345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP_{c}	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{hb,\, LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{pb,hb,\, LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HUBDF}_{hb,\, LRGV138/345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{pb,\, hb,\, LRGV138/345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{hb,\, LRGV138/345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$\text{HBBC}_{LRGV138/345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$\text{HB}_{LRGV138/345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{LRGV138/345} = \mathbf{Max\ [-\$251,\ (RTRDP\ +} \sum_{y} \mathbf{(HUBLMP}_{LRGV138/345,\, y} \mathbf{\ *\ RNWF}_{y}\mathbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{LRGV138/345kV}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA_{y}	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$\text{HUBLMP}_{LRGV138/345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.6 ERCOT Hub Average 345 kV Hub (ERCOT 345)

(1) The ERCOT Hub Average 345 kV Hub price for Day-Ahead is calculated for each hour using the aggregated Shift Factors of four Hubs: the North 345 kV Hub, the South 345 kV Hub, the Houston 345 kV Hub, and the West 345 kV Hub. The ERCOT Hub Average 345 kV Hub price for Real-Time is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price. The Panhandle 345 kV Hub is not included in either the Day-Ahead or Real-Time ERCOT Hub Average 345 kV Hub price.

[NPRR941: Replace paragraph (1) above upon system implementation:]

(1) The ERCOT Hub Average 345 kV Hub price for Day-Ahead is calculated for each hour using the aggregated Shift Factors of four Hubs: the North 345 kV Hub, the South 345 kV Hub, the Houston 345 kV Hub, and the West 345 kV Hub. The ERCOT Hub Average 345 kV Hub price for Real-Time is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price. The Panhandle 345 kV

Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in either the Day-Ahead or Real-Time ERCOT Hub Average 345 kV Hub price.

(2) The Day-Ahead Settlement Point Price for the Hub "ERCOT 345" for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{ERCOT345} = \mathbf{DASL} - \sum_{c}(\mathbf{DAHUBSF}_{ERCOT345,\,c} * \mathbf{DASP}_{c}), \text{ if } \mathbf{HBBC}_{ERCOT345Bus} \neq 0$$

$$\mathbf{DASPP}_{ERCOT345} = \mathbf{DASPP}_{ERCOT345Bus}, \text{ if } \mathbf{HBBC}_{ERCOT345Bus} = 0$$

Where:

$$\text{DAHUBSF}_{ERCOT345,\,c} = (\text{DAHUBSF}_{North345,\,c} + \text{DAHUBSF}_{South345,\,c} + \text{DAHUBSF}_{Houston345,\,c} + \text{DAHUBSF}_{West345,\,c}) / 4$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DASPP $_{ERCOT345}$	\$/MWh	*Day-Ahead Settlement Point Price at ERCOT 345*—The DAM Settlement Point Price at ERCOT 345 Hub for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{ERCOT345,c}$	none	*Day-Ahead Shift Factor of ERCOT 345* —The DAM aggregated Shift Factor of ERCOT 345 Hub for the constraint *c* for the hour.
DAHUBSF $_{North345,c}$	none	*Day-Ahead Shift Factor of North 345*—The DAM aggregated Shift Factor of the North 345 Hub for the constraint *c* for the hour.
DAHUBSF $_{South345,c}$	none	*Day-Ahead Shift Factor of South 345*—The DAM aggregated Shift Factor of the South 345 Hub for the constraint *c* for the hour.
DAHUBSF $_{Houston345,c}$	none	*Day-Ahead Shift Factor of Houston 345*—The DAM aggregated Shift Factor of the Houston 345 Hub for the constraint *c* for the hour.
DAHUBSF $_{West345,c}$	none	*Day-Ahead Shift Factor of West 345*—The DAM aggregated Shift Factor of the West 345 Hub for the constraint *c* for the hour.
HBBC $_{ERCOT345Bus}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus in base case. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(3) The Real-Time Settlement Point Price for the Hub "ERCOT 345" for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{ERCOT345}} = (\mathbf{RTSPP}_{\mathit{North345}} + \mathbf{RTSPP}_{\mathit{South345}} + \mathbf{RTSPP}_{\mathit{Houston345}} + \mathbf{RTSPP}_{\mathit{West345}}) / 4$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RTSPP}_{\mathit{ERCOT345}}$	\$/MWh	*Real-Time Settlement Point Price at ERCOT 345*—The Real-Time Settlement Point Price at ERCOT 345 Hub for the 15-minute Settlement Interval.
$\text{RTSPP}_{\mathit{North345}}$	\$/MWh	*Real-Time Settlement Point Price at North 345*—The Real-Time Settlement Point Price at the North 345 Hub for the 15-minute Settlement Interval.
$\text{RTSPP}_{\mathit{South345}}$	\$/MWh	*Real-Time Settlement Point Price at South 345*—The Real-Time Settlement Point Price at the South 345 Hub for the 15-minute Settlement Interval.
$\text{RTSPP}_{\mathit{Houston345}}$	\$/MWh	*Real-Time Settlement Point Price at Houston 345*—The Real-Time Settlement Point Price at the Houston 345 Hub for the 15-minute Settlement Interval.
$\text{RTSPP}_{\mathit{West345}}$	\$/MWh	*Real-Time Settlement Point Price at West 345*—The Real-Time Settlement Point Price at the West 345 Hub for the 15-minute Settlement Interval.

3.5.2.7 ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus)

(1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4, West 345 kV Hub (West 345). The Panhandle 345 kV Hub is not included in the ERCOT Bus Average 345 kV Hub price.

[NPRR941: Replace paragraph (1) above upon system implementation:]

(1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4, West 345 kV Hub (West 345). The Panhandle 345 kV Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in the ERCOT Bus Average 345 kV Hub price.

(2) The ERCOT Bus Average 345 kV Hub uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\mathit{ERCOT345Bus}} = \mathbf{DASL} - \sum_{c}(\mathbf{DAHUBSF}_{\mathit{ERCOT345Bus,\,c}} * \mathbf{DASP}_{c}), \text{ if } \mathbf{HBBC}_{\mathit{ERCOT345Bus}} \neq 0$$

$$\mathbf{DASPP}_{\mathit{ERCOT345Bus}} = 0, \text{ if } \mathbf{HBBC}_{\mathit{ERCOT345Bus}} = 0$$

Where:

$$\text{DAHUBSF}_{\,ERCOT345Bus,\,c} = \sum_{hb} (\text{HUBDF}_{\,hb,\,ERCOT345Bus,\,c} * \text{DAHBSF}_{\,hb,\,ERCOT345Bus,\,c})$$

$$\text{DAHBSF}_{\,hb,\,ERCOT345Bus,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,ERCOT345Bus,\,c} * \text{DASF}_{\,pb,\,hb,\,ERCOT345Bus,\,c})$$

$$\text{HUBDF}_{\,hb,\,ERCOT345Bus,\,c} = \text{IF}(\text{HB}_{\,ERCOT345Bus,\,c}=0,\ 0,\ 1\ /\ \text{HB}_{\,ERCOT345Bus,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,ERCOT345Bus,\,c} = \text{IF}(\text{PB}_{\,hb,\,ERCOT345Bus,\,c}=0,\ 0,\ 1\ /\ \text{PB}_{\,hb,\,ERCOT345Bus,\,c})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{\,ERCOT345Bus}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
$\text{DASP}_{\,c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{\,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{\,hb,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{\,pb,hb,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HUBDF}_{\,hb,ERCOT345Bus,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{\,pb,\,hb,\,ERCOT345Bus,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{\,hb,\,ERCOT345Bus,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized power flow bus for the constraint *c*. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
$\text{HBBC}_{\,ERCOT345Bus}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus in base case. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
$\text{HB}_{\,ERCOT345Bus,c}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus for the constraint *c*. The Hub "ERCOT 345 Bus" includes any Hub Bus

Variable	**Unit**	**Definition**
		defined in the Hub “North 345”, “South 345”, “Houston 345” and “West 345”.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{ERCOT345Bus}} = \mathbf{Max\ [-\$251,\ (RTRSVPOR + RTRDP + \sum_{hb} (HUBDF}_{\mathit{hb,\ ERCOT345Bus}} \mathbf{*\ (\sum_{y} (RTHBP}_{\mathit{hb,\ ERCOT345Bus,\ y}} \mathbf{*\ TLMP}_{\mathit{y}}\mathbf{)\ /\ (\sum_{y} TLMP}_{\mathit{y}}\mathbf{))))],\ if\ HB}_{\mathit{ERCOT345Bus}} \mathbf{\neq 0}$$

$$\mathbf{RTSPP}_{\mathbf{ERCOT345Bus}} = \mathbf{0,\ if\ HB}_{\mathbf{ERCOT345Bus}} \mathbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

$$\text{RTHBP}_{hb,\ ERCOT345Bus,\ y} = \sum_{b} (\text{HBDF}_{b,\ hb,\ ERCOT345Bus} * \text{RTLMP}_{b,\ hb,\ ERCOT345Bus,\ y})$$

$$\text{HUBDF}_{hb,\ ERCOT345Bus} = 1 / (\text{HB}_{North345} + \text{HB}_{South345} + \text{HB}_{Houston345} + \text{HB}_{West345})$$

If Electrical Bus *b* is a component of “North 345”

$\text{HBDF}_{b,\ hb,\ ERCOT345Bus} = \text{IF}(\text{B}_{hb,\ North345}=0,\ 0,\ 1 / \text{B}_{hb,\ North345})$

Otherwise

If Electrical Bus *b* is a component of “South 345”

$\text{HBDF}_{b,\ hb,\ ERCOT345Bus} = \text{IF}(\text{B}_{hb,\ South345}=0,\ 0,\ 1 / \text{B}_{hb,\ South345})$

Otherwise

If Electrical Bus *b* is a component of “Houston 345”

$\text{HBDF}_{b,\ hb,\ ERCOT345Bus} = \text{IF}(\text{B}_{hb,\ Houston345}=0,\ 0,\ 1 / \text{B}_{hb,\ Houston345})$

Otherwise

$\text{HBDF}_{b,\ hb,\ ERCOT345Bus} = \text{IF}(\text{B}_{hb,\ West345}=0,\ 0,\ 1 / \text{B}_{hb,\ West345})$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$\text{RTSPP}_{\mathit{ERCOT345Bus}}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTHBP}_{\mathit{hb, ERCOT345Bus, y}}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$\text{RTLMP}_{\mathit{b, hb, ERCOT345Bus, y}}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$\text{HUBDF}_{\mathit{hb, ERCOT345Bus}}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$\text{HBDF}_{\mathit{b, hb, ERCOT345Bus}}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$\text{B}_{\mathit{hb, North345}}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “North 345.”
$\text{B}_{\mathit{hb, South345}}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “South 345.”
$\text{B}_{\mathit{hb, Houston345}}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “Houston 345.”
$\text{B}_{\mathit{hb, West345}}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “West 345.”
hb	none	A Hub Bus that is a component of the Hub.
$\text{HB}_{\mathit{North345}}$	none	The total number of Hub Buses in “North 345.”
$\text{HB}_{\mathit{South345}}$	none	The total number of Hub Buses in “South 345.”
$\text{HB}_{\mathit{Houston345}}$	none	The total number of Hub Buses in “Houston 345.”
$\text{HB}_{\mathit{West345}}$	none	The total number of Hub Buses in “West 345.”

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,ERCOT345Bus} = \mathbf{Max\ [-\$251,\ (RTRDP + \sum_{y} (HUBLMP_{\mathit{ERCOT345Bus,y}} * RNWF_{\mathit{y}}))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{ERCOT345Bus}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA_{y}	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y.*
$\text{HUBLMP}_{ERCOT345Bus,y}$	\$/MWh	*Hub Locational Marginal Price for the ERCOT345Bus*—The Hub LMP for the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus), for the SCED Interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.3 ERCOT Responsibilities for Managing Hubs

3.5.3.1 Posting of Hub Buses and Electrical Buses included in Hubs

(1) ERCOT shall post a list of all the Hub Buses included in each Hub on the ERCOT website. The list must include the name and kV rating for each Electrical Bus included in each Hub Bus.

3.5.3.2 Calculation of Hub Prices

(1) ERCOT shall calculate Hub prices for each Settlement Interval as identified in the description of each Hub.

3.6 Load Participation

3.6.1 Load Resource Participation

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

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

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

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

[NPRR863: Insert paragraph (iv) below upon system implementation and renumber accordingly:]

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

(iv) Non-Spinning Reserve (Non-Spin) as a Controllable Load Resource qualified for SCED Dispatch or as a Load Resource that is not a

Controllable Load Resource and that is not controlled by under-frequency relay; and

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

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

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

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

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

(d) Voluntary Load response in Real-Time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.6.2 Decision Making Entity for a Resource

(1) Each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall submit a declaration to ERCOT, using Section 23, Form C, Managed Capacity Declaration, as to which Decision Making Entity (DME) has control of each of

its Resources. The declaration shall be signed by the Authorized Representative of the Resource Entity. In addition, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall notify ERCOT of any known changes in that declaration no later than 14 days prior to the date that the change takes effect, or as soon as possible in a situation where the Resource Entity is unable to meet the 14-day Notice requirement. However, in no event may the Resource Entity inform ERCOT later than 72 hours before the date on which the change in DME takes effect. Upon ERCOT's request, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall provide ERCOT with sufficient information or documentation to verify the DME's control of the Resource. ERCOT shall update the DME for a Resource effective the first Operating Hour of the Operating Day after ERCOT satisfactorily confirms the Resource Entity's most recent declaration, but not sooner than the effective date specified on the Resource Entity's most recent declaration.

3.7 Resource Parameters

(1) A Resource Entity shall register Generation Resources, Settlement Only Generators (SOGs), and Load Resources pursuant to Planning Guide Section 6.8, Resource Registration Procedures. The Resource Parameters, listed in Section 3.7.1, Resource Parameter Criteria, are a subset of Resource Registration data defined in the Resource Registration Glossary.

[NPRR995 and NPRR1002: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) A Resource Entity shall register its Generation Resources, Energy Storage Resources (ESRs), Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Load Resources pursuant to Planning Guide Section 6.8, Resource Registration Procedures. The Resource Parameters, listed in Section 3.7.1, Resource Parameter Criteria, are a subset of Resource Registration data defined in the Resource Registration Glossary.

(2) ERCOT shall provide each Qualified Scheduling Entity (QSE) that represents a Resource the ability to submit changes to Resource Parameters for that Resource as described in Section 3.7.1.

(3) The QSE may revise Resource Parameters only with sufficient documentation to justify a change in Resource Parameters.

(4) ERCOT shall use the Resource Parameters as inputs into the Day-Ahead Market (DAM), Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), Resource Limit Calculator, Load Frequency Control (LFC), and other ERCOT business processes.

(5) The Independent Market Monitor (IMM) may require the QSE to provide justification for the Resource Parameters submitted.

3.7.1 Resource Parameter Criteria

3.7.1.1 Generation Resource Parameters

(1) Generation Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation include:

  (a) Normal Ramp Rate curve;

  (b) Emergency Ramp Rate curve;

  (c) Minimum On-Line time;

  (d) Minimum Off-Line time;

  (e) Maximum On-Line time;

  (f) Maximum daily starts;

  (g) Maximum weekly starts;

  (h) Maximum weekly energy;

  (i) Hot start time;

  (j) Intermediate start time;

  (k) Cold start time;

  (l) Hot to intermediate time; and

  (m) Intermediate to cold time.

3.7.1.2 Load Resource Parameters

(1) Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation, which may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements, include the following for each of its Load Resources that is a non-Controllable Load Resource:

  (a) Maximum interruption time;

(b) Maximum daily deployments;

(c) Maximum weekly deployments;

(d) Maximum weekly energy;

(e) Minimum notice time;

(f) Minimum interruption time; and

(g) Minimum restoration time.

(2) Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation, which may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, include the following for each of its Controllable Load Resources, including Aggregate Load Resources (ALRs):

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Maximum deployment time; and

(d) Maximum weekly energy.

(3) Resource Parameters submitted by a Resource Entity must also include, for each of its ALRs, mapping between the ALR and the individually metered Loads, by Electric Service Identifier (ESI ID) or, in the case of a Non-Opt-In Entity (NOIE), equivalent unique meter identifier, comprising the ALR.

[NPRR1002: Insert Section 3.7.1.3 below upon system implementation:]

3.7.1.3 Energy Storage Resource Parameters

(1) Resource Parameters for an ESR that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation include:

(a) Normal Ramp Rate curve; and

(b) Emergency Ramp Rate curve.

3.7.2 Changes in Resource Parameters with Operational Impacts

(1) The QSE representing each Resource shall have the responsibility to submit changes to Resource Parameters for those Resource Parameters related to the Current Operating Plan (COP), as described in Section 3.9, Current Operating Plan (COP), and to Real-Time

operations as described in Section 6, Adjustment Period and Real-Time Operations. If the QSE cancels a Resource Parameter submission, ERCOT will use as a default the Resource Parameter that is registered in the Network Operations Model.

3.7.3 Resource Parameter Validation

(1) ERCOT shall verify that changes to Resource Parameters submitted by the QSE representing the Resource comply with the Resource Registration Glossary. If a Resource Parameter is determined to be invalid, then ERCOT shall reject it and provide written notice to the QSE representing the Resource of the reason for the rejection.

3.8 Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources

[NPRR1026: Replace Section 3.8 above with the following upon system implementation:]

3.8 Special Considerations

3.8.1 Split Generation Resources

(1) When a generation meter is split, as provided for in Section 10.3.2.1, Generation Resource Meter Splitting, two or more independent Generation Resources must be created in the ERCOT Network Operations Model according to Section 3.10.7.2, Modeling of Resources and Transmission Loads, to function in all respects as Split Generation Resources in ERCOT System operation. A Combined Cycle Train may not be registered in ERCOT as a Split Generation Resource. A Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) may not be registered in ERCOT as a Split Generation Resource.

(2) Each Qualified Scheduling Entity (QSE) representing a Split Generation Resource shall collect and shall submit to ERCOT the Resource Parameters defined under Section 3.7, Resource Parameters, for the Split Generation Resource it represents. The parameters provided must be consistent with the parameters submitted by each other QSE that represents a Split Generation Resource from the same Generation Resource. The parameters submitted for each Split Generation Resource for limits and ramp rates must be according to the capability of the Split Generation Resource represented by the QSE. Startup and shutdown times, time to change status and number of starts must be identical for all the Split Generation Resources from the same Generation Resource submitted by each QSE. ERCOT shall review data submitted by each QSE representing Split Generation Resources for consistency and notify each QSE of any errors.

(3) Each Split Generation Resource may be represented by a different QSE. The Resource Entities that own or control the Split Generation Resources from a single Generation Resource must designate a Master QSE. Each QSE representing a Split Generation Resource must comply in all respects to the requirements of a Generation Resource specified under these Protocols.

(4) The Master QSE shall:

(a) Serve as the Single Point of Contact for the Generation Resource, as required by Section 3.1.4.1, Single Point of Contact;

(b) Provide real-time telemetry for the total Generation Resource, as specified in Section 6.5.5.2, Operational Data Requirements; and

(c) Receive Verbal Dispatch Instructions (VDIs) from ERCOT, as specified in Section 6.5.7.8, Dispatch Procedures.

(5) Each QSE is responsible for representing its Split Generation Resource in its Current Operating Plan (COP). During the Reliability Unit Commitment (RUC) Study Periods, any conflict in the Resource Status of a Split Generation Resource in the COP is resolved according to the following:

(a) If a Split Generation Resource has a Resource Status of OUT for any hour in the COP, then any other QSEs' COP entries for their Split Generation Resources from the same Generation Resource are also considered unavailable for the hour;

(b) If the QSEs for all Split Generation Resources from the same Generation Resource have submitted a COP and at least one of the QSEs has an On-Line Resource Status in a given hour, then the status for all Split Generation Resources for the Generation Resource is considered to be On-Line for that hour, except if any of the QSEs has indicated in the COP a Resource Status of OUT.

(6) Each QSE representing a Split Generation Resource shall update its individual Resource Status appropriately.

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split Generation Resources in a single Generation Resource must be committed or decommitted together.

[NPRR1007: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves, Ancillary Service Offers, and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split

Generation Resources in a single Generation Resource must be committed or decommitted together.

(8) Each QSE submitting verifiable cost data to ERCOT shall coordinate among all owners of a single Generation Resource to provide individual Split Generation Resource data consistent with the total verifiable cost of the entire Generation Resource. ERCOT may compare the total verifiable costs with other similarly situated Generation Resources to determine the reasonability of the cost.

3.8.2 Combined Cycle Generation Resources

(1) ERCOT shall assign a logical Resource Node for use in the Day-Ahead Market (DAM), RUC, Supplemental Ancillary Services Market (SASM), Security-Constrained Economic Dispatch (SCED) and Load Frequency Control (LFC) to each registered Combined Cycle Train. Each Combined Cycle Generation Resource registered in the Combined Cycle Train will be mapped to the Combined Cycle Train logical Resource Node for the purposes of evaluating and settling each Combined Cycle Generation Resource's Three-Part Supply Offer and Ancillary Service Offer in the DAM, RUC and SCED. Each generation unit identified in the Combined Cycle Train registration for a Combined Cycle Generation Resource configuration will be mapped to its designated Resource Node as determined in accordance with these Protocols and the Other Binding Document titled "Procedure for Identifying Resource Nodes."

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall assign a logical Resource Node for use in the Day-Ahead Market (DAM), RUC, Security-Constrained Economic Dispatch (SCED) and Load Frequency Control (LFC) to each registered Combined Cycle Train. Each Combined Cycle Generation Resource registered in the Combined Cycle Train will be mapped to the Combined Cycle Train logical Resource Node for the purposes of evaluating and settling each Combined Cycle Generation Resource's Three-Part Supply Offer and Ancillary Service Offer in the DAM, RUC and SCED. Each generation unit identified in the Combined Cycle Train registration for a Combined Cycle Generation Resource configuration will be mapped to its designated Resource Node as determined in accordance with these Protocols and the Other Binding Document titled "Procedure for Identifying Resource Nodes."

(2) If any of the generation units, designated in the Combined Cycle Train registration as a primary generation unit in a Combined Cycle Generation Resource, is isolated from the ERCOT Transmission Grid because of a transmission Outage reported in the Outage Scheduler, the DAM and RUC applications shall select an alternate generation unit for use in the application.

(3) Three-Part Supply Offers submitted for a Combined Cycle Generation Resource will be modeled as High Reasonability Limit (HRL)-weighted injections at the Resource Connectivity Nodes of the associated Generation Resources. ERCOT shall use the logical Resource Node to settle these offers.

(4) In the DAM and RUC, ERCOT shall model the energy injection from each generation unit registered to the Combine Cycle Generation Resource designated in a Three-Part Supply Offer as follows:

(a) The energy injection for each generation unit registered in the Combined Cycle Generation Resource designated in a Three-Part Supply Offer shall be the offered energy injection for the selected price point on the Three-Part Supply Offer's Energy Offer Curve times a weight factor as determined in paragraph (4)(b) below.

(b) The weight factor for each generation unit registered in a Combined Cycle Generation Resource shall be the generation unit's HRL, as specified in the Resource Registration data provided to ERCOT pursuant to Planning Guide Section 6.8.2, Resource Registration Process, divided by the total of all HRL values for the generation units registered in the designated Combined Cycle Generation Resource.

(5) In the Network Operations Network Models used in the DAM, RUC and SCED applications, each generation unit identified in the Combined Cycle Train registration must be modeled at its Resource Connectivity Node.

(6) For Ancillary Services offered and provided from Combined Cycle Generation Resources, ERCOT shall apply, without exception, the same rules and requirements specified in these Protocols for the DAM, RUC and Adjustment Period and Real-Time markets that apply to Ancillary Services provided from any other Generation Resources.

(a) ERCOT systems shall determine the High and Low Ancillary Service Limits (HASL and LASL) for a Combined Cycle Generation Resource as follows:

(i) In Real Time, relative to the telemetered High Sustained Limit (HSL) for the Combined Cycle Generation Resource, or

(ii) During the DAM and RUC study periods, relative to the HSL in the COP.

(b) The QSE shall assure that the Combined Cycle Generation Resource designated as On-Line through telemetry or in the COP can meet its Ancillary Service Resource Responsibility.

[NPRR1007: Replace paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) For Ancillary Services offered and provided from Combined Cycle Generation Resources, ERCOT shall apply, without exception, the same rules and requirements specified in these Protocols for the DAM, RUC and Adjustment Period and Real-Time markets that apply to Ancillary Services provided from any other Generation Resources.

(a) ERCOT systems shall determine the operating limits for a Combined Cycle Generation Resource as follows:

(i) In Real-Time, relative to the telemetered capacity limits, ramp rates, and Ancillary Service capabilities for the Combined Cycle Generation Resource;

(ii) During the DAM study period, relative to the HSL in the COP; or

(iii) During the RUC Study Period, relative to the capacity limits and Ancillary Service capabilities in the COP.

3.8.3 Quick Start Generation Resources

(1) The QSE for a Quick Start Generation Resource (QSGR) that is available for deployment by SCED shall set the COP Resource Status to OFFQS, and the COP Low Sustained Limit (LSL) and COP HSL values to the expected sustainable LSL and HSL for the QSGR for the hour. If the QSGR is providing Non-Spinning Reserve (Non-Spin) service, then the Ancillary Service Resource Responsibility for Non-Spin shall be set to the Resource's QSE-assigned Non-Spin responsibility in the COP.

[NPRR863 and NPRR1007: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

(1) The QSE for a Quick Start Generation Resource (QSGR) that is available for deployment by SCED and awarding of ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin), if qualified and capable, shall set the COP Resource Status to OFFQS, and the COP Low Sustained Limit (LSL) and COP HSL values to the expected sustainable LSL and HSL for the QSGR for the hour.

(2) The QSGR that is available for deployment by SCED shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource's actual output until the Resource has ramped to its physical LSL.

After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL. The QSGR that is providing Off-Line Non-Spin shall always telemeter an Ancillary Service Resource Responsibility for Non-Spin to reflect the Resource's Non-Spin obligation and shall always telemeter an Ancillary Service Schedule for Non-Spin of zero to make the capacity available for SCED.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) The QSGR that is available for deployment by SCED and awarding of ECRS and Non-Spin, if qualified and capable, shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched and/or awarded ECRS and Non-Spin. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource's actual output until the Resource has ramped to its physical LSL. After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL.

(3) A QSGR with a telemeter breaker status of open and a telemeter Resource Status OFFQS shall not provide Regulation Service or Responsive Reserve (RRS).

(4) ERCOT shall adjust the QSGR's Mitigated Offer Cap (MOC) curve as described in Section 4.4.9.4.1, Mitigated Offer Cap.

(5) For a QSGR that is physically Off-Line, the Resource Entity shall submit a Normal Ramp Rate curve and Emergency Ramp Rate curve indicating QSGR's ability to reach its ten-minute tested output from zero output in five minutes. This is necessary to prevent SCED from deploying multiple QSGRs due to ramp limitation in the first five minutes after being Dispatched by SCED. QSGRs shall be exempt from Base Point Deviation Charges as described in Section 6.6.5.3, Resources Exempt from Deviation Charges.

[NPRR1007: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(5) For a QSGR that is physically Off-Line, the Resource Entity shall submit a Normal Ramp Rate curve and Emergency Ramp Rate curve indicating QSGR's ability to reach its ten-minute tested output from zero output in five minutes. This is necessary to prevent SCED from deploying multiple QSGRs due to ramp limitation in the first five minutes after being Dispatched by SCED. QSGRs shall be exempt from Set Point Deviation Charges as described in Section 6.6.5.3, Resources Exempt from Deviation Charges.

(6) Any hour in which the QSE for the QSGR has shown the Resource as available for SCED Dispatch as described in this Section 3.8.3 is considered a QSE-Committed Interval.

(7) QSEs must submit and maintain an Energy Offer Curve for their QSGRs for all hours in which the COP Resource Status is submitted as OFFQS. If a valid Energy Offer Curve or an Output Schedule does not exist for any QSGR for which a Resource Status of OFFQS is telemetered at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then-current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period. For use as SCED inputs, ERCOT shall create proxy Energy Offer Curves for the Resource as described in paragraph (4) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(8) Other than for the potential decommitment of a QSGR as described in Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process, following a SCED QSGR deployment, the QSGR is expected to follow the SCED Base Points.

3.8.3.1 Quick Start Generation Resource Decommitment Decision Process

(1) For purposes of determining whether SCED needs a QSGR to continue to generate per paragraph (3) of Section 6.6.9, Emergency Operations Settlement, the QSE representing the QSGR shall telemeter an LSL of zero for at least one but no more than two non-consecutive SCED executions in each Operating Hour during which the QSGR is operating with a SCED Base Point equal to its registered LSL and shall telemeter Normal and Emergency Ramp Rates indicating that the QSGR can be Dispatched to zero output in a single SCED interval.

(a) If the SCED issued Base Point for the QSGR is non-zero in the interval where a zero LSL has been telemetered by the QSE, then the QSGR is deemed needed by SCED and the QSE shall immediately resume telemetering an LSL equal to the physical LSL and continue to operate the unit following subsequent Base Points.

(b) If the Base Point is zero, then the QSE will decommit the QSGR using normal operating practices.

(c) If at any point during the period in which the QSGR is in SHUTDOWN mode, the QSGR Locational Marginal Price (LMP) is greater than or equal to the Energy Offer Curve price, capped per Section 4.4.9.4.1, Mitigated Offer Cap, the QSE may reverse the decommitment process, if possible and make the QSGR available for SCED following normal operating practices.

3.8.4 Generation Resources Operating in Synchronous Condenser Fast-Response Mode

(1) A QSE is considered to have performed for the amount of its RRS obligation for the MW amount provided by a Generation Resource operating in synchronous condenser fast-response mode and triggered by an under-frequency relay device at the frequency set

point specified in paragraph (3)(c) of Section 3.18, Resource Limits in Providing Ancillary Service, without corresponding RRS deployment by ERCOT. This provision applies only for the duration when RRS MW is deployed by automatic under-frequency relay action.

3.8.5 Energy Storage Resources

(1) The Resource Entity and QSE representing an Energy Storage Resource (ESR) which is jointly registered with ERCOT as a Generation Resource and a Controllable Load Resource, pursuant to paragraph (6) of Section 16.5, Registration of a Resource Entity, are responsible for following all requirements in these Protocols associated with Generation Resources and Controllable Load Resources.

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

(1) For the purposes of all ERCOT Protocols and Other Binding Documents, all requirements that apply to Generation Resources and Controllable Load Resources shall be understood to apply to Energy Storage Resources (ESRs) to the same extent, except where the Protocols explicitly provide otherwise.

(2) A QSE representing an ESR may update the telemetered HSL and/or Maximum Power Consumption (MPC) for the ESR in Real-Time to ensure the ability to meet the ESR's full Ancillary Service Resource Responsibility for the current Operating Hour. This provision only applies when the MOC for an ESR is set at the System-Wide Offer Cap (SWCAP) pursuant to paragraph (1)(b) of Section 4.4.9.4.1, Mitigated Offer Cap.

[NPRR1075: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

(3) A QSE representing an ESR may update the telemetered HSL and/or MPC for the ESR in Real-Time to reflect state of charge limitations.

[NPRR1075: Replace paragraph (3) above with the following upon system implementation of NPRR1014:]

(3) A QSE representing an ESR may update the telemetered HSL and/or LSL for the ESR in Real-Time to reflect state of charge limitations.

(4) A QSE representing an ESR co-located with a Generation Resource may reduce the telemetered MPC of the Controllable Load Resource modeled to represent the charging side of the ESR when self-charging using output from the Generation Resource. Such reduction in MPC shall be equal to the MW level of self-charge.

[NPRR1075: Replace paragraph (4) above with the following upon system implementation of NPRR1014:]

(4) A QSE representing an ESR co-located with a Generation Resource may update the telemetered LSL of the ESR when self-charging (using output from the Generation Resource). The updated LSL shall be equal to the MW level of self-charge.

3.8.6 Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)

(1) As a condition for the interconnection of a DGR or DESR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall provide documentation from the DSP to ERCOT stating that the interconnecting distribution circuit will not be disconnected as part of an Energy Emergency Alert (EEA) Level 3, an under-frequency Load shedding event, or an under-voltage Load shedding event, unless required for DSP local system maintenance or during a DSP local system emergency.

(a) If a DSP subsequently determines that any circuit to which a DGR or DESR is interconnected will need to be disconnected during these Load shedding events, or that a DGR or DESR will need to be moved to a circuit that will be disconnected during these Load shedding events:

(i) The DSP shall promptly notify the designated contact for the DGR or DESR;

(ii) The Resource Entity shall promptly notify ERCOT of this fact via the Resource Registration process; and

(iii) The DGR or DESR will immediately be disqualified from offering to provide any Ancillary Service.

(b) Upon receiving notification from the DSP that the DGR or DESR is no longer subject to disconnection during any of these Load shedding events, and that no known system limitations or changes have occurred that would inhibit the DGR or DESR from complying with Ancillary Service performance requirements, the Resource Entity for the DGR or DESR shall notify ERCOT of this fact via the Resource Registration process and will, at that time, be eligible to offer to provide Ancillary Services if the Resource is otherwise qualified to do so.

(2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or DESR, the interconnecting DSP will evaluate the proposed conversion and will determine whether it is electrically and operationally feasible. If the interconnecting DSP determines that the conversion is not electrically or operationally feasible, the DSP may disallow the conversion.

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

(2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or for a proposed conversion of an existing Settlement Only Distribution Energy Storage System (SODESS) to a DESR, the interconnecting DSP will evaluate the proposed conversion and will determine whether it is electrically and operationally feasible. If the interconnecting DSP determines that the conversion is not electrically or operationally feasible, the DSP may disallow the conversion.

(3) The Resource Node for a DGR or DESR shall be fixed at a single Electrical Bus in the ERCOT Network Operations Model.

(a) If a DSP determines that a topology change has altered, or is expected to alter, the electrical path connecting the DGR or DESR to the ERCOT Transmission Grid for a period longer than 60 days:

(i) The DSP shall promptly notify the interconnecting Transmission Service Provider (TSP) and the designated contact for the DGR or DESR, and the interconnecting TSP shall notify ERCOT; and

(ii) The Resource Entity shall submit a change request to ERCOT via the Resource Registration process.

[NPRR1026 and NPRR1077: Insert applicable portions of Section 3.8.7 below upon system implementation:]

3.8.7 Self-Limiting Facility

(1) A Resource Entity or Interconnecting Entity (IE) for a Self-Limiting Facility may establish a MW Injection or MW Withdrawal limit by submitting an attestation in a form designated by ERCOT through the Resource Registration process. The Resource Entity or IE shall simultaneously provide a copy of the attestation to the interconnecting Transmission and/or Distribution Service Provider (TDSP). All registered generators or Energy Storage Systems (ESSs) within a Self-Limiting Facility shall be represented by a single Resource Entity and a single QSE.

(2) A Self-Limiting Facility shall not inject or withdraw power in excess of its established MW Injection limit or its established MW Withdrawal limit.

(3) On a monthly basis, ERCOT will report to the Reliability Monitor and IMM any instance where a Self-Limiting Facility's actual MW Injections exceeded the MW Injection limit or where actual MW Withdrawals exceeded the MW Withdrawal limit established in the Resource Registration data for the Self-Limiting Facility, based on the telemetry of the injection and withdrawal values provided by the QSE for the registered

generator or ESS in the Self-Limiting Facility, as described in Section 3.9.1, Current Operating Plan (COP) Criteria, and in Section 6.5.5.2, Operational Data Requirements, or based on the meter data at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for the Self-Limiting Facility.

(4) If requested by ERCOT, the relevant QSE shall provide meter data to confirm whether the established limits for a Self-Limiting Facility were violated.

(5) If ERCOT determines that a Self-Limiting Facility connected at transmission voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data by more than the greater of 5 MW or 3% of the limit, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall deregister as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to the established MW Injection limit and any established MW Withdrawal limit until the generation interconnection process has been completed.

(6) A Distribution Service Provider (DSP) may limit injections and withdrawals from any Generation Resource, Settlement Only Generator (SOG), or ESR based on Resource Registration data and the interconnection agreement between the DSP and the IE or Resource Entity. In that case, the IE or Resource Entity shall submit the attestation required by paragraph (1) above, and shall be considered a Self-Limiting Facility.

(7) If ERCOT determines that a Self-Limiting Facility connected at distribution voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall be deregistered as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to any MW Injection or MW Withdrawal limit until the generation interconnection process has been completed.

(8) The interconnecting TDSP, at its sole discretion, may use relaying to ensure a Self-Limiting Facility does not inject or withdraw energy in excess of its MW Injection or MW Withdrawal limits in order to protect the TDSP's limiting element(s).

[NPRR1029 and NPRR1111: Insert applicable portions of Section 3.8.8 below upon system implementation for NPRR1029; or upon system implementation of SCR819 for NPRR1111:]

3.8.8 DC-Coupled Resources

(1) A DC-Coupled Resource shall be treated in the same manner as an Energy Storage Resource (ESR) for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, Set Point Deviation Charge, and Energy Storage Resource

Energy Deployment Performance (ESREDP), as described in Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, under one of the following conditions:

(a) The Resource was awarded Ancillary Service;

(b) The Resource's instantaneous MW Injection or MW Withdrawal includes non-zero MW from the ESS component of the DC-Coupled Resource; or

(c) The Resource's telemetered HSL or LSL includes the ESS capability.

(2) At all other times, a DC-Coupled Resource shall be treated in the same manner as an IRR for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, and ESREDP, as described in Section 8.1.1.4.1.

(3) A QSE representing a DC-Coupled Resource that does not meet any of the conditions in paragraph (1) above:

(a) Shall set the Resource's telemetered HSL equal to the current net output capability of the intermittent renewable generation component of the DC-Coupled Resource; and

(b) Shall set the Resource's output at or below the SCED Base Point telemetered by ERCOT if the Resource receives a flag indicating that SCED has dispatched it below the Resource's HDL used by SCED or that it has been instructed not to exceed its Base Point.

3.9 Current Operating Plan (COP)

(1) Each Qualified Scheduling Entity (QSE) that represents a Resource must submit a Current Operating Plan (COP) under this Section.

(2) ERCOT shall use the information provided in the COP to calculate the High Ancillary Service Limit (HASL) and Low Ancillary Service Limit (LASL) for each Resource for the Reliability Unit Commitment (RUC) processes.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) ERCOT shall use the information provided in the COP to calculate operating limits and Ancillary Service capabilities for each Resource for the Reliability Unit Commitment (RUC) processes.

(3) ERCOT shall monitor the accuracy of each QSE's COP as outlined in Section 8, Performance Monitoring.

(4) A QSE must notify ERCOT that it plans to have a Resource On-Line by means of the COP using the Resource Status codes listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria. The QSE must show the Resource as On-Line with a Resource Status of ONRUC, indicating a RUC process committed the Resource for all RUC-Committed Intervals. A QSE may only use a RUC-committed Resource during that Resource's RUC-Committed Interval to meet the QSE's Ancillary Service Supply Responsibility if the Resource has been committed by the RUC process to provide Ancillary Service.

(5) To reflect changes to a Resource's capability, each QSE shall report by exception, changes to the COP for all hours after the Operating Period through the rest of the Operating Day.

(6) When a QSE updates its COP to show changes in Resource Status, the QSE shall update for each On-Line Resource, either an Energy Offer Curve under Section 4.4.9, Energy Offers and Bids, or Output Schedule under Section 6.4.2, Output Schedules.

(7) Each QSE, including QSEs representing Reliability Must-Run (RMR) Units, Firm Fuel Supply Service Resources (FFSSRs), or Black Start Resources, shall submit a revised COP reflecting changes in Resource availability as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change.

(8) Each QSE representing a Qualifying Facility (QF) must submit a Low Sustained Limit (LSL) that represents the minimum energy available, in MW, from the unit for economic dispatch based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

3.9.1 Current Operating Plan (COP) Criteria

(1) Each QSE that represents a Resource must submit a COP to ERCOT that reflects expected operating conditions for each Resource for each hour in the next seven Operating Days.

(2) Each QSE that represents a Resource shall update its COP reflecting changes in availability of any Resource as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change.

[NPRR1085: Replace paragraph (2) above with the following upon system implementation:]

(2) Each QSE that represents a Resource shall update its COP reflecting changes in availability of any Resource as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change. Each QSE shall timely update its COP unless in the reasonable judgment of the QSE, such compliance would create an

undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating the COP only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the COP begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

(3) The Resource capacity in a QSE's COP must be sufficient to supply the Ancillary Service Supply Responsibility of that QSE.

[NPRR1007, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(3) Each QSE that represents a Resource shall update its COP to reflect the ability of the Resource to provide each Ancillary Service by product and sub-type.

(4) Load Resource COP values may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements.

(5) A COP must include the following for each Resource represented by the QSE:

(a) The name of the Resource;

(b) The expected Resource Status:

(i) Select one of the following for Generation Resources synchronized to the ERCOT System that best describes the Resource's status. Unless otherwise provided below, these Resource Statuses are to be used for COP and/or Real-Time telemetry purposes, as appropriate.

(A) ONRUC – On-Line and the hour is a RUC-Committed Hour;

(B) ONREG – On-Line Resource with Energy Offer Curve providing Regulation Service;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (B) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(C) ON – On-Line Resource with Energy Offer Curve;

(D) ONDSR – On-Line Dynamically Scheduled Resource (DSR);

[NPRR1000: Delete item (D) above upon system implementation and renumber accordingly.]

(E) ONOS – On-Line Resource with Output Schedule;

(F) ONOSREG – On-Line Resource with Output Schedule providing Regulation Service;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (F) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(G) ONDSRREG – On-Line DSR providing Regulation Service;

[NPRR1000, NPRR1007, NPRR1014, and NPRR1029: Delete item (G) above upon system implementation for NPRR1000, NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; and renumber accordingly.]

(H) FRRSUP – Available for Dispatch of Fast Responding Regulation Service (FRRS). This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (H) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 and NPRR1029; and renumber accordingly.]

(I) ONTEST – On-Line blocked from Security-Constrained Economic Dispatch (SCED) for operations testing (while ONTEST, a Generation Resource may be shown on Outage in the Outage Scheduler);

(J) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and High Sustained Limit (HSL) to reflect operating limits);

(K) ONRR – On-Line as a synchronous condenser providing Responsive Reserve (RRS) but unavailable for Dispatch by SCED and available for commitment by RUC;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (K) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(L) ONECRS – On-Line as a synchronous condenser providing ERCOT Contingency Response Service (ECRS) but unavailable for Dispatch by SCED and available for commitment by RUC;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (L) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(M) ONOPTOUT – On-Line and the hour is a RUC Buy-Back Hour;

(N) SHUTDOWN – The Resource is On-Line and in a shutdown sequence, and has no Ancillary Service Obligations other than Off-Line Non-Spinning Reserve (Non-Spin) which the Resource will provide following the shutdown. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (N) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(N) SHUTDOWN – The Resource is On-Line and in a shutdown sequence, and is not eligible for an Ancillary Service award. This Resource Status is only to be used for Real-Time telemetry purposes;

(O) STARTUP – The Resource is On-Line and in a start-up sequence and has no Ancillary Service Obligations. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (O) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(O) STARTUP – The Resource is On-Line and in a start-up sequence and is not eligible for an Ancillary Service award, unless coming On-Line in response to a manual deployment of ERCOT Contingency Reserve Service (ECRS) or Non-Spinning

Reserve (Non-Spin). This Resource Status is only to be used for Real-Time telemetry purposes;

(P) OFFQS – Off-Line but available for SCED deployment. Only qualified Quick Start Generation Resources (QSGRs) may utilize this status; and

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (P) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(P) OFFQS – Off-Line but available for SCED deployment and to provide ECRS and Non-Spin, if qualified and capable. Only qualified Quick Start Generation Resources (QSGRs) may utilize this status;

(Q) ONFFRRRS – Available for Dispatch of RRS when providing Fast Frequency Response (FFR) from Generation Resources. This Resource Status is only to be used for Real-Time telemetry purposes. A Resource with this Resource Status may also be providing Ancillary Services other than FFR;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (Q) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

[NPRR1007, NPRR1014, NPRR1029, and NPRR1085: Insert applicable portions of items (K) and (L) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014, NPRR1029, or NPRR1085:]

(K) ONSC – Resource is On-Line operating as a synchronous condenser and available to provide Responsive Reserve (RRS) and ECRS, if qualified and capable, and for commitment by RUC, but is unavailable for Dispatch by SCED. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution; and

(L) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards. This Resource Status is only to be used for Real-Time telemetry purposes. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution.

(ii) Select one of the following for Off-Line Generation Resources not synchronized to the ERCOT System that best describes the Resource's status. These Resource Statuses are to be used for COP and/or Real-Time telemetry purposes, as appropriate.

(A) OUT – Off-Line and unavailable, or not connected to the ERCOT System and operating in a Private Microgrid Island (PMI);

(B) OFFNS – Off-Line but reserved for Non-Spin;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (B) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(C) OFF – Off-Line but available for commitment in the Day-Ahead Market (DAM) and RUC;

[NPRR1007, NPRR1014, and NPRR1029: Replace item (C) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(B) OFF – Off-Line but available for commitment in the Day-Ahead Market (DAM), RUC, and providing Non-Spin, if qualified and capable;

(D) EMR – Available for commitment as a Resource contracted by ERCOT under Section 3.14.1, Reliability Must Run, or under paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority, or available for commitment only for ERCOT-declared Emergency Condition events; the QSE may appropriately set LSL and HSL to reflect operating limits;

(E) EMRSWGR – Switchable Generation Resource (SWGR) operating in a non-ERCOT Control Area, or in the case of a Combined Cycle Train with one or more SWGRs, a configuration in which one or more of the physical units in that configuration are operating in a non-ERCOT Control Area.

(iii) Select one of the following for Load Resources. Unless otherwise provided below, these Resource Statuses are to be used for COP and/or Real-Time telemetry purposes.

(A) ONRGL – Available for Dispatch of Regulation Service by Load Frequency Control (LFC) and, for any remaining Dispatchable capacity, by SCED with a Real-Time Market (RTM) Energy Bid;

(B) FRRSUP – Available for Dispatch of FRRS by LFC and not Dispatchable by SCED. This Resource Status is only to be used for Real-Time telemetry purposes;

(C) FRRSDN - Available for Dispatch of FRRS by LFC and not Dispatchable by SCED. This Resource Status is only to be used for Real-Time telemetry purposes;

(D) ONCLR – Available for Dispatch as a Controllable Load Resource by SCED with an RTM Energy Bid;

(E) ONRL – Available for Dispatch of RRS or Non-Spin, excluding Controllable Load Resources;

[NPRR1007, NPRR1014, and NPRR1029: Delete items (A)-(E) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(F) ONECL – Available for Dispatch of ECRS, excluding Controllable Load Resources;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (F) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(G) OUTL – Not available;

(H) ONFFRRRSL – Available for Dispatch of RRS when providing FFR, excluding Controllable Load Resources. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (H) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029.]

[NPRR1007, NPRR1014, NPRR1029: Insert item (B) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(B) ONL – On-Line and available for Dispatch by SCED or providing Ancillary Services.

[NPRR1014 or NPRR1029: Insert applicable portions of paragraph (iv) below upon system implementation:]

(iv) Select one of the following for Energy Storage Resources (ESRs). Unless otherwise provided below, these Resource Statuses are to be used for COP and Real-Time telemetry purposes:

(A) ON – On-Line Resource with Energy Bid/Offer Curve;

(B) ONOS – On-Line Resource with Output Schedule;

(C) ONTEST – On-Line blocked from SCED for operations testing (while ONTEST, an Energy Storage Resource (ESR) may be shown on Outage in the Outage Scheduler);

(D) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and High Sustained Limit (HSL) to reflect operating limits);

(E) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards. ESRs shall not be discharging into or charging from the grid. This Resource Status is only to be used for Real-Time telemetry purposes; and

(F) OUT – Off-Line and unavailable, or not connected to the ERCOT System and operating in a Private Microgrid Island (PMI);

(c) The HSL;

(i) For Load Resources other than Controllable Load Resources, the HSL should equal the expected power consumption;

[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (ii) below upon system implementation:]

(ii) For ESRs, the HSL may be negative;

(d) The LSL;

(i) For Load Resources other than Controllable Load Resources, the LSL should equal the expected Low Power Consumption (LPC);

[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (ii) below upon system implementation:]

(ii) For ESRs, the LSL may be positive;

(e) The High Emergency Limit (HEL);

(f) The Low Emergency Limit (LEL); and

(g) Ancillary Service Resource Responsibility capacity in MW for:

[NPRR1007, NPRR1014, and NPRR1029: Replace applicable portions of item (g) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(g) Ancillary Service capability in MW for each product and sub-type.

(i) Regulation Up (Reg-Up);

(ii) Regulation Down (Reg-Down);

(iii) RRS;

(iv) ECRS; and

(v) Non-Spin.

[NPRR1007, NPRR1014, and NPRR1029: Delete items (i)-(v) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029.]

(6) For Combined Cycle Generation Resources, the above items are required for each operating configuration. In each hour only one Combined Cycle Generation Resource in a Combined Cycle Train may be assigned one of the On-Line Resource Status codes described above.

(a) During a RUC study period, if a QSE’s COP reports multiple Combined Cycle Generation Resources in a Combined Cycle Train to be On-Line for any hour, then until the QSE corrects its COP, the On-Line Combined Cycle Generation Resource with the largest HSL is considered to be On-Line and all other Combined Cycle Generation Resources in the Combined Cycle Train are considered to be Off-Line. Furthermore, until the QSE corrects its COP, the Off-Line Combined Cycle Generation Resources as designated through the application of this process are ineligible for RUC commitment or de-commitment Dispatch Instructions.

(b) For any hour in which QSE-submitted COP entries are used to determine the initial state of a Combined Cycle Generation Resource for a DAM or Day-Ahead Reliability Unit Commitment (DRUC) study and the COP shows multiple Combined Cycle Generation Resources in a Combined Cycle Train to be in an On-line Resource Status, then until the QSE corrects its COP, the On-Line Combined Cycle Generation Resource that has been On-Line for the longest time from the last recorded start by ERCOT systems, regardless of the reason for the start, combined with the COP Resource Status for the remaining hours of the current Operating Day, is considered to be On-Line at the start of the DRUC study period and all other COP-designated Combined Cycle Generation Resources in the Combined Cycle Train are considered to be Off-Line.

(c) ERCOT systems shall allow only one Combined Cycle Generation Resource in a Combined Cycle Train to offer Off-Line Non-Spin in the DAM or Supplemental Ancillary Services Market (SASM).

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(c) ERCOT systems shall allow only one Combined Cycle Generation Resource in a Combined Cycle Train to offer Off-Line Non-Spin in the DAM or SCED.

(i) If there are multiple Non-Spin offers from different Combined Cycle Generation Resources in a Combined Cycle Train, then prior to execution of the DAM, ERCOT shall select the Non-Spin offer from the Combined Cycle Generation Resource with the highest HSL for consideration in the DAM and ignore the other offers.

(ii) Combined Cycle Generation Resources offering Off-Line Non-Spin must be able to transition from the shutdown state to the offered Combined Cycle Generation Resource On-Line state and be capable of ramping to the full amount of the Non-Spin offered.

(d) The DAM and RUC shall honor the registered hot, intermediate or cold Startup Costs for each Combined Cycle Generation Resource registered in a Combined Cycle Train when determining the transition costs for a Combined Cycle Generation Resource. In the DAM and RUC, the Startup Cost for a Combined Cycle Generation Resource shall be determined by the positive transition cost from the On-Line Combined Cycle Generation Resource within the Combine

Cycle Train or from a shutdown condition, whichever ERCOT determines to be appropriate.

(7) ERCOT may accept COPs only from QSEs.

(8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). ERCOT will notify the QSE via an Extensible Markup Language (XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT.

[NPRR1029: Replace paragraph (8) above with the following upon system implementation:]

(8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). A QSE representing a DC-Coupled Resource shall provide the capacity value of the Energy Storage System (ESS) that is included in the HSL of the DC-Coupled Resource, and ERCOT will update the DC-Coupled Resource’s HSL with the sum of the forecasts of the intermittent renewable generation component and the QSE-submitted value for the ESS component. ERCOT will notify the QSE via an Extensible Markup Language (XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT. A QSE representing a DC-Coupled Resource may override the COP HSL value with a value that is lower than the ERCOT-populated value, and may override with a value that is higher than the ERCOT-populated value if the ESS component of the DC-Coupled Resource can support the higher value.

(9) A QSE representing a Generation Resource that is not actively providing Ancillary Services or is providing Off-Line Non-Spin that the Resource will provide following the shutdown, may only use a Resource Status of SHUTDOWN to indicate to ERCOT through telemetry that the Resource is operating in a shutdown sequence or a Resource Status of ONTEST to indicate in the COP and through telemetry that the Generation Resource is performing a test of its operations either manually dispatched by the QSE or

by ERCOT as part of the test. A QSE representing a Generation Resource that is not actively providing Ancillary Services may only use a Resource Status of STARTUP to indicate to ERCOT through telemetry that the Resource is operating in a start-up sequence requiring manual control and is not available for Dispatch.

(10) If a QSE has not submitted a valid COP for any Generation Resource for any hour in the DAM or RUC Study Period, then the Generation Resource is considered to have a Resource Status as OUT thus not available for DAM awards or RUC commitments for those hours.

(11) If a COP is not available for any Resource for any hour from the current hour to the start of the DAM period or RUC study, then the Resource Status for those hours are considered equal to the last known Resource Status from a previous hour's COP or from telemetry as appropriate for that Resource.

(12) A QSE representing a Resource may only use the Resource Status code of EMR for a Resource whose operation would have impacts that cannot be monetized and reflected through the Resource's Energy Offer Curve or recovered through the RUC make-whole process or if the Resource has been contracted by ERCOT under Section 3.14.1 or under paragraph (4) of Section 6.5.1.1. If ERCOT chooses to commit an Off-Line unit with EMR Resource Status that has been contracted by ERCOT under Section 3.14.1 or under paragraph (4) of Section 6.5.1.1, the QSE shall change its Resource Status to ONRUC. Otherwise, the QSE shall change its Resource Status to ONEMR.

(13) A QSE representing a Resource may use the Resource Status code of ONEMR for a Resource that is:

(a) On-Line, but for equipment problems it must be held at its current output level until repair and/or replacement of equipment can be accomplished; or

(b) A hydro unit.

(14) A QSE operating a Resource with a Resource Status code of ONEMR may set the HSL and LSL of the unit to be equal to ensure that SCED does not send Base Points that would move the unit.

(15) A QSE representing a Resource may use the Resource Status code of EMRSWGR only for an SWGR.

[NPRR1026: Insert paragraph (16) below upon system implementation:]

(16) A QSE representing a Self-Limiting Facility must ensure that the sum of the COP HSL/LSL and the sum of the telemetered HSL/LSL submitted for each Resource within the Self-Limiting Facility do not exceed either the limit on MW Injection or the limit on the MW Withdrawal established for the Self-Limiting Facility.

[NPRR1029: Insert paragraph (16) below upon system implementation:]

(16) A QSE representing a DC-Coupled Resource shall not submit an HSL that exceeds the inverter rating or the sum of the nameplate ratings of the generation component(s) of the Resource.

3.9.2 Current Operating Plan Validation

(1) ERCOT shall verify that each COP, on its submission, complies with the criteria described in Section 3.9.1, Current Operating Plan (COP) Criteria. ERCOT shall notify the QSE by means of the Messaging System if the QSE's COP fails to comply with the criteria described in Section 3.9.1 and this Section 3.9.2 for any reason. The QSE must then resubmit the COP within the appropriate market timeline.

(2) ERCOT may reject a COP that does not meet the criteria described in Section 3.9.1.

(3) If a Resource is designated in the COP to provide Ancillary Service, then ERCOT shall verify that the COP complies with Section 3.16, Standards for Determining Ancillary Service Quantities. The Ancillary Service Supply Responsibilities as indicated in the Ancillary Service Resource Responsibility submitted immediately before the end of the Adjustment Period are physically binding commitments for each QSE for the corresponding Operating Period.

(4) ERCOT shall notify the QSE if the sum of the Ancillary Service capacity designated in the COP for each hour, by service type, is less than the QSE's Ancillary Service Supply Responsibility for each service type for that hour. If the QSE does not correct the deficiency within one hour after receiving the notice from ERCOT, then ERCOT shall follow the procedures outlined in Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency.

(5) A QSE may change Ancillary Service Resource designations by changing its COP, subject to Section 6.4.9.1.

(6) If ERCOT determines that it needs more Ancillary Service during the Adjustment Period, then the QSE's allocated portion of the additional Ancillary Service may be self-arranged.

[NPRR1007: Delete paragraphs (3)-(6) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(7) ERCOT systems must be able to detect a change in status of a Resource shown in the COP and must provide notice to ERCOT operators of changes that a QSE makes to its COP.

(8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP may not designate a Resource Status of ONOS or ONDSR for that hour for that Resource.

[NPRR1000: Replace paragraph (8) above with the following upon system implementation:]

(8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP may not designate a Resource Status of ONOS for that hour for that Resource.

3.10 Network Operations Modeling and Telemetry

(1) ERCOT shall use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from the Transmission Service Providers (TSPs) and Resource Entities to specify limits within which the transmission network is defined in the network models made available to Market Participants as noted below and used to operate the ERCOT Transmission Grid as updated. If a Private Use Network is not registered as a Resource Entity, then ERCOT shall use equivalent model data provided by TSPs, if available, that represents the Private Use Network in the TSPs' modeling systems for use in the Network Operations Model.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT shall use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), and Resource Entities to specify limits within which the transmission network is defined in the network models made available to Market Participants as noted below and used to operate the ERCOT Transmission Grid as updated. If a Private Use Network is not registered as a Resource Entity, then ERCOT shall use equivalent model data provided by TSPs, if available, that represents the Private Use Network in the TSPs' modeling systems for use in the Network Operations Model.

(2) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants' responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary

for reliability reasons, manage within ratings provided by the TSP and Resource Entity and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants' responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary for reliability reasons, manage within ratings provided by each TSP, DCTO, and Resource Entity and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

(3) TSPs and Resource Entities shall provide ERCOT with equipment ratings and update the ratings as required by ERCOT. ERCOT may request TSPs and Resource Entities to provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the Market Information System (MIS) Secure Area within seven days following a change in methodology.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) Each TSP, DCTO, and Resource Entity shall provide ERCOT with equipment ratings and update the ratings as required by ERCOT. ERCOT may request that a TSP, DCTO, or Resource Entity provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the Market Information System (MIS) Secure Area within seven days following a change in methodology.

(4) ERCOT must use system ratings consistent with the ratings expected to be used during Real-Time for the system condition being modeled, including Dynamic Ratings using expected temperatures for those system conditions. For each model, ERCOT shall post ratings and the ambient temperatures used to calculate the ratings on the MIS Secure Area when the model is published.

(5) ERCOT shall use consistent information within and between the various models used by ERCOT in a manner that yields consistent results. For operational and planning models that are intended to represent the same system state the results should be consistent and the naming should be identical.

(6) ERCOT shall use a Network Operations Model Change Request (NOMCR) process to control all information entering the Network Operations Model. In order to allow for construction schedules, each NOMCR must be packaged as a single package describing any incremental changes and referencing any prerequisite NOMCRs, using an industry standard data exchange format. A package must contain a series of instructions that define the changes that need to be made to implement a network model change. ERCOT shall verify each package for completeness and accuracy prior to the period it is to be implemented.

(7) ERCOT shall use an automated process to manage the Common Information Model (CIM) compliant packages loaded into the Network Operations Model as each construction phase is completed. ERCOT shall reject any NOMCRs that are not CIM compliant. Each CIM compliant NOMCR must also be associated with commands to update the graphical displays associated with the network model modification. During the testing phase, each NOMCR must be tested for proper sequencing and its effects on downstream applications.

(8) ERCOT shall track each data submittal received from TSPs via the NOMCR process and from Resource Entities via the Resource Registration process. Resource Registration data is converted by ERCOT to the appropriate NOMCR format through implementation and final testing of the change. ERCOT shall notify each TSP and Resource Entity when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall also provide the submitting TSP a link to a Network Operations Model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Certified Area for TSPs only within five Business Days following receipt of the NOMCR, consistent with the requirements regarding ERCOT Critical Energy Infrastructure Information (ECEII) set forth in Section 1.3, Confidentiality. When posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last Network Operations Model for TSPs only, to facilitate TSPs in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Certified Area for TSPs only the current status on the in-service date for each NOMCR, including any prerequisite NOMCRs provided by the requestor.

[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(8) ERCOT shall track each data submittal received from TSPs and DCTOs via the NOMCR process and from Resource Entities via the Resource Registration process. Resource Registration data is converted by ERCOT to the appropriate NOMCR format through implementation and final testing of the change. ERCOT shall notify each TSP, DCTO, and Resource Entity when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall also provide the submitting TSP and DCTO a link to a Network Operations Model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Certified Area for TSPs only within five Business Days following receipt of the NOMCR, consistent with the requirements regarding ERCOT Critical Energy Infrastructure Information (ECEII) set forth in Section 1.3, Confidentiality. When posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last Network Operations Model for TSPs only, to facilitate TSPs in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Certified Area for TSPs only the current status on the in-service date for each NOMCR, including any prerequisite NOMCRs provided by the requestor.

(9) ERCOT shall update the Network Operations Model under this Section and coordinate it with the planning models for consistency to the extent applicable.

(10) Any requestor of any changes in system topology or telemetry must receive approval from ERCOT before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its submittal for changes in system topology or telemetry. ERCOT shall accept corrections to the submittal if the requestor has corrected any deficiencies by the required submittal date specified in Section 3.10.1. ERCOT shall post any changes to an NOMCR on the MIS Certified Area for TSPs within three Business Days of accepting corrections.

[NPRR857: Replace paragraph (10) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(10) Any requestor of any changes in system topology or telemetry must receive approval from ERCOT before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its submittal for changes in system topology or telemetry. ERCOT shall accept corrections to the submittal if the requestor has corrected any deficiencies by the required submittal date specified in Section 3.10.1. ERCOT shall post any changes to a NOMCR on the MIS Certified Area for TSPs and DCTOs within three Business Days of accepting corrections.

(11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for any new or relocated facilities. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any ERCOT requested changes to the work plan. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the revised NOMCR on the MIS Certified Area for TSPs.

[NPRR857: Replace paragraph (11) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for any new or relocated facilities. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any ERCOT requested changes to the work plan. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the revised NOMCR on the MIS Certified Area for TSPs and DCTOs.

3.10.1 Time Line for Network Operations Model Changes

(1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs, DCTOs, and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource or Settlement Only Generator (SOG) as described in Planning Guide Section 5, Generator Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource or SOG.

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource, Settlement Only Generator (SOG), or Settlement Only Energy Storage System (SOESS) as described in Planning Guide Section 5, Generator Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning

Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource, SOG, or SOESS.

(3) TSPs and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. ERCOT shall update the Network Operations Model according to the following table:

Deadline to Submit Information to ERCOT **Note 1**	**Model Complete and Available for Test** **Note 2**	**Updated Network Operations Model Testing Complete** **Note 3** **Paragraph (5)**	**Update Network Operations Model Production Environment**	**Target Physical Equipment included in Production Model** **Note 4**
Jan 1	Feb 15	March 15	April 1	Month of April
Feb 1	March 15	April 15	May 1	Month of May
March 1	April 15	May 15	June 1	Month of June
April 1	May 15	June 15	July 1	Month of July
May 1	June 15	July 15	August 1	Month of August
June 1	July 15	August 15	September 1	Month of September
July 1	August 15	September 15	October 1	Month of October
August 1	September 15	October 15	November 1	Month of November
September 1	October 15	November 15	December 1	Month of December
October 1	November 15	December 15	January 1	Month of January (the next year)
November 1	December 15	January 15	February 1	Month of February (the next year)
December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. TSP and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.
4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) TSPs, DCTOs, and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. ERCOT shall update the Network Operations Model according to the following table:

Deadline to Submit Information to ERCOT **Note 1**	**Model Complete and Available for Test** **Note 2**	**Updated Network Operations Model Testing Complete** **Note 3** **Paragraph (5)**	**Update Network Operations Model Production Environment**	**Target Physical Equipment included in Production Model** **Note 4**
Jan 1	Feb 15	March 15	April 1	Month of April
Feb 1	March 15	April 15	May 1	Month of May
March 1	April 15	May 15	June 1	Month of June
April 1	May 15	June 15	July 1	Month of July
May 1	June 15	July 15	August 1	Month of August
June 1	July 15	August 15	September 1	Month of September
July 1	August 15	September 15	October 1	Month of October
August 1	September 15	October 15	November 1	Month of November
September 1	October 15	November 15	December 1	Month of December
October 1	November 15	December 15	January 1	Month of January (the next year)
November 1	December 15	January 15	February 1	Month of February (the next year)
December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. TSP, DCTO, and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy

Management System (EMS) testing prior to placing the new model into the production environment.

4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

(4) ERCOT shall only approve energization requests when the Transmission Element is satisfactorily modeled in the Network Operations Model.

(5) Changes to an existing NOMCR that modify only Inter-Control Center Communications Protocol (ICCP) data object names shall be provided 15 days prior to the Network Operations Model load date. NOMCR modifications containing only ICCP data object names shall not be subject to interim update reporting to the Independent Market Monitor (IMM) and Public Utility Commission of Texas (PUCT) (reference Section 3.10.4), according to the following:

NOMCR that contains ICCP Data and is submitted …	***ERCOT shall …***	***Subject to IMM & PUC Reporting***
Beyond 90 days of the energization date	Allow modification of only ICCP data for an existing NOMCR	No
Between 90 and 15 days prior to the scheduled database load.	Allow modification of only ICCP data for an existing NOMCR	No
Less than 15 days before scheduled database load.	Require a new NOMCR to be submitted containing the ICCP data	Yes

3.10.2 Annual Planning Model

(1) For each of the next six years, ERCOT shall develop models for annual planning purposes that contain, as much as practicable, information consistent with the Network Operations Model. The "Annual Planning Model" for each of the next six years is a model of the ERCOT power system (created, approved, posted, and updated regularly by ERCOT) as it is expected to operate during peak Load conditions for the corresponding future year.

(2) By October 15th of each year, ERCOT shall update, for each of the next six years, the ERCOT Planning Model and post it to the MIS Secure Area

(3) ERCOT shall make available to TSPs and/or Distribution Service Provider (DSPs) and all appropriate Market Participants, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, the transmission model used in transmission planning. ERCOT shall provide model information through the use of the Electric Power Research Institute (EPRI) and North American Electric Reliability Corporation (NERC) sponsored CIM and web-based Extensible Markup Language (XML) communications or Power System Simulator for Engineering (PSS/E) format.

(4) ERCOT shall post the schedule for updating transmission information on the MIS Secure Area.

(5) ERCOT shall coordinate updates to the Annual Planning Model with the Network Operations Model to ensure consistency of data within and between the Annual Planning Model and Network Operations Model to the extent practicable.

3.10.3 CRR Network Model

(1) ERCOT shall develop models for Congestion Revenue Right (CRR) Auctions that contain, as much as practicable, information consistent with the Network Operations Model. Names of Transmission Elements in the Network Operations Model and the CRR Network Model must be identical for the same physical equipment.

(2) ERCOT shall verify that the names of Hub Buses and Electrical Buses used to describe the same device in any Hub are identically named in both the Network Operations Model and the CRR Network Model.

(3) Each CRR Network Model must include:

(a) A system-wide diagram including all modeled Transmission Elements (except those within Private Use Networks) and Resource Nodes;

(b) Station one-line diagrams for all Settlement Points (indicating the Settlement Point that the Electrical Bus is a part of) and including all Hub Buses used to calculate Hub prices (if applicable), except those within Private Use Networks;

(c) Generation Resource locations;

(d) Transmission Elements;

(e) Transmission impedances;

(f) Transmission ratings, excluding Relay Loadability Ratings;

(g) Contingency lists;

(h) Data inputs used in the calculation of Dynamic Ratings, and

(i) Other relevant assumptions and inputs used for the CRR Network Model.

(4) ERCOT shall make available to TSPs and/or DSPs and all appropriate Market Participants, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, the CRR Network Model. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web based XML communications or PSS/E format.

3.10.3.1 Process for Managing Network Operations Model Updates for Point of Interconnection Bus Changes, Resource Retirements and Deletion of DC Tie Load Zones

(1) Following the permanent change in Point of Interconnection Bus (POIB) of all Resources associated with a Resource Node, ERCOT shall retain the associated Settlement Point in the Network Operations Model at its existing location, an electrically similar location, or until all outstanding CRRs associated with that Settlement Point have expired as determined in accordance with the Other Binding Document, “Procedure for Identifying Resource Nodes.” Following the retirement of all Resources associated with a Resource Node, ERCOT shall move the Resource Node to a proxy Electrical Bus. The proxy Electrical Bus will be selected by finding the nearest energized Electrical Bus with the least impedance equipment between the existing Resource Node and the proxy Electrical Bus. For purposes of the CRR Auction model for calendar periods that are prior to the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will continue to be available as a sink or source for CRR Auction transaction submittals. For calendar periods that are beyond the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will not be available for transaction submittals in the associated CRR Auctions. The Settlement Point will be removed from the Network Operations Model once all associated CRRs have expired.

(2) When a Direct Current Tie (DC Tie) is to be permanently removed from service, ERCOT will delete the associated DC Tie Load Zone from the Network Operations Model after all outstanding CRRs associated with that DC Tie Load Zone have expired. The DC Tie Load Zone will continue to be available as a sink or source Settlement Point for transaction submittals in CRR Auctions for calendar periods that are prior to the scheduled deletion date of the DC Tie Load Zone; however, the DC Tie Load Zone will no longer be an available Settlement Point for transaction submittals in CRR Auctions for calendar periods that are after the scheduled deletion date of the DC Tie Load Zone.

3.10.4 ERCOT Responsibilities

(1) ERCOT shall design, install, operate, and maintain its systems and establish applicable related processes to meet the State Estimator Standards for Transmission Elements that under typical system conditions potentially affect the calculation of Locational Marginal Prices (LMPs) as described in Section 3.10.7.5, Telemetry Standards, and Section 3.10.9, State Estimator Standards. ERCOT shall post all documents relating to the State Estimator Standards on the MIS Secure Area.

(2) During Real-Time, ERCOT shall calculate LMPs and take remedial actions to ensure that actual flow on a given Transmission Element is less than the Normal Rating and any calculated flow due to a contingency is less than the applicable Emergency Rating and 15-Minute Rating.

(3) ERCOT shall install Network Operations Model test facilities that will accommodate execution of a test Real-Time sequence and preliminary test LMP calculator to

demonstrate the correct operation of new Network Operations Models prior to releasing the model to Market Participants for detail testing and verification. The Network Operations Model test facilities support power flow and contingency analyses to test the data set representation of a proposed transmission model update and simulate LMP calculations using typical test data.

(4) ERCOT shall install EMS test and simulation facilities that accommodate execution of the State Estimator and LMP calculator, respectively. These facilities will be used to conduct tests prior to placing a new model into ERCOT's production environment to verify the new model's accuracy. The EMS test facilities allow a potential model to be tested before replacing the current production environment model. The EMS test and simulation facilities must perform Real-Time security analysis to test a proposed transmission model before replacing the current production environment model. The EMS State Estimator test facilities must have Real-Time ICCP links to test the state estimation function using actual Real-Time conditions. The EMS LMP test facilities must accept data uploads from the production environment providing Qualified Scheduling Entity (QSE) Resource offers, and telemetry via ICCP. If the production data are unavailable, ERCOT may employ a data simulation tool or process to develop test data sets for the LMP test facilities. For TSPs, ERCOT shall acquire model comparison software that will show all differences between subsequent versions of the Network Operations Model and shall make this information available to TSPs only within one week following test completion. For non-TSP Market Participants, ERCOT shall post the differences within one week following test completion between subsequent versions of the Redacted Network Operations Model on the MIS Secure Area. This comparison shall indicate differences in device parameters, missing or new devices, and status changes.

(5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP and Resource Entity shall provide reasonably accurate information at the time of the original submission.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP, DCTO, and Resource Entity shall provide reasonably accurate information at the time of the original submission.

(6) ERCOT may update the model on an interim basis, outside of the timeline described in Section 3.10.1, Time Line for Network Operations Model Changes, for the correction of

temporary configuration changes in a system restoration situation, such as after a storm, or correction of impedances and ratings.

(7) Interim updates to the Network Operations Model caused by unintentional inconsistencies of the model with the physical transmission grid may be made. If an interim update is implemented, ERCOT shall report changes to the PUCT Staff and the IMM. ERCOT shall provide Notice via electronic means to all Market Participants and post the Notice on the MIS Secure Area detailing the changed model information and the reason for the interim update within two Business Days following the report to PUCT Staff and the IMM.

(8) A TSP and Resource Entity, with ERCOT's assistance, shall validate its portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, to an environment of the ERCOT EMS where the Network Operations Model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results.

[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(8) TSPs, DCTOs, and Resource Entities, with ERCOT's assistance, shall validate their portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, to an environment of the ERCOT EMS where the Network Operations Model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results.

(9) ERCOT shall make available to TSPs, consistent with the requirements regarding ECEII, the Network Operations Model used to manage the reliability of the transmission system as well as proposed Network Operations Models to be implemented at a future date. ERCOT shall post on the MIS Secure Area the Redacted Network Operations Model, consistent with the requirements regarding release of ECEII, as well as proposed Redacted Network Operations Models to be implemented at a future date. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web-based XML communications.

3.10.5 TSP Responsibilities

(1) Each TSP shall design, implement, operate, and maintain its systems to meet the requirements of Section 3.10.7.5, Telemetry Requirements, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already existing installations except as shown to be needed in order to comply with Section 3.10.7.5 and Section 3.10.9, State Estimator Requirements.

(2) TSPs shall add telemetry to equipment it owns and directly operates and controls at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. Nothing in this subsection prohibits a TSP from adding telemetry to equipment it does not own but directly operates and controls. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) Each TSP shall provide to ERCOT planned construction information, including Certificate of Convenience and Necessity (CCN) application milestone dates if applicable, all of which shall be updated according to a schedule established by ERCOT.

(4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Reliability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.

(5) A QSE must receive approval from a TSP prior to using the TSP's telemetry as part of a Generation Resource's Bulk Electric System protection scheme or for generation control. If a TSP has approved a QSE's use of the TSP's telemetry, the TSP shall inform the QSE of any telemetry changes with reasonable notice prior to the change or where prior notice is not possible as soon as reasonably practicable thereafter, including discontinuation of the TSP's provision of such telemetry, and the timeline for the changes.

[NPRR857: Replace Section 3.10.5 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

3.10.5 TSP and DCTO Responsibilities

(1) Each TSP and DCTO shall design, implement, operate, and maintain its systems to meet the requirements of Section 3.10.7.5, Telemetry Requirements, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained

Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already existing installations except as shown to be needed in order to comply with Section 3.10.7.5 and Section 3.10.9, State Estimator Requirements.

(2) Each TSP and DCTO shall add telemetry to equipment it owns and directly operates and controls at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. Nothing in this subsection prohibits a TSP from adding telemetry to equipment it does not own but directly operates and controls. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) Each TSP and DCTO shall provide to ERCOT planned construction information, including Certificate of Convenience and Necessity (CCN) application milestone dates if applicable, all of which shall be updated according to a schedule established by ERCOT.

(4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Reliability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.

(5) A QSE must receive approval from a TSP prior to using the TSP's telemetry as part of a Generation Resource's Bulk Electric System protection scheme or for generation control. If a TSP has approved a QSE's use of the TSP's telemetry, the TSP shall inform the QSE of any telemetry changes with reasonable notice prior to the change or where prior notice is not possible as soon as reasonably practicable thereafter, including discontinuation of the TSP's provision of such telemetry, and the timeline for the changes.

3.10.6 QSE and Resource Entity Responsibilities

(1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation Resource, SOG, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

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

(1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation

Resource, SOG, SOESS, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

(2) QSEs shall ensure availability of telemetry to generation and transmission equipment its Resource Entity owns at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5, Telemetry Requirements. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

3.10.7 ERCOT System Modeling Requirements

(1) The following subsections contain the fidelity requirements for the ERCOT Network Operations Model.

3.10.7.1 Modeling of Transmission Elements and Parameters

(1) ERCOT, each TSP, and each Resource Entity shall coordinate to define each Transmission Element such that the TSP's control center operational model and ERCOT's Network Operations Model are consistent.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT and each TSP, DCTO, and Resource Entity shall coordinate to define each Transmission Element such that the TSP's control center operational model and ERCOT's Network Operations Model are consistent.

(2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT, Resource Entities, and TSPs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of the Technical Advisory Committee (TAC). In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to

cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT, Resource Entities, TSPs, and DCTOs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of TAC. In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day.

(3) If the responsible TSP submits a NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) If the responsible TSP or DCTO submits a NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request.

(4) Resource Entities shall provide the data requested in this Section through the Resource Registration data provided pursuant to Planning Guide Section 6.8.2, Resource Registration Process.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) Each Resource Entity shall provide the data requested in this Section through the Resource Registration data provided pursuant to relevant authorities, including Planning Guide Section 6.8.2, Resource Registration Process.

[NPRR1133: Insert paragraph (5) below upon system implementation of NPRR857:]

(5) Each DC Tie Facility owner shall provide the model data needed to accurately reflect the physical characteristics of the DC Tie Facility in ERCOT's Network Operations Model to its DCTO, and the DCTO shall submit the data to ERCOT. The DC Tie Facility owner is responsible for the accuracy and completeness of the data submitted to ERCOT through its DCTO.

3.10.7.1.1 Transmission Lines

(1) ERCOT shall model each transmission line that operates in excess of 60 kV.

(2) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP and if applicable, Resource Entity, shall provide ERCOT with the following information consistent with the ratings methodology prescribed in the ERCOT Operating Guides:

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information consistent with the ratings methodology prescribed in the ERCOT Operating Guides:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) Transmission Element name;

(d) Line impedance;

(e) Normal Rating, Emergency Rating, 15-Minute Rating, Conductor/Transformer 2-Hour Rating, and Relay Loadability Rating; and

(f) Other data necessary to model Transmission Element(s).

(3) The TSP and Resource Entity may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-

making authority and responsibility to determine the limits to be applied in grid operations.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) The TSP, DCTO, and Resource Entity may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-making authority and responsibility to determine the limits to be applied in grid operations.

(4) The TSP and Resource Entity may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP and Resource Entity obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP and Resource Entity shall include those limits as Relay Loadability Ratings when providing ERCOT with ratings or proposed transfer limits.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) The TSP, DCTO, and Resource Entity may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP, DCTO, and Resource Entity obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP, DCTO, and Resource Entity shall include those limits as Relay Loadability Ratings when providing ERCOT with ratings or proposed transfer limits.

(5) The Network Operations Model must use rating categories for Transmission Elements as defined in the ERCOT Operating Guides.

3.10.7.1.2 Transmission Buses

(1) ERCOT shall model each Electrical Bus that operates as part of the ERCOT Transmission Grid in excess of 60 kV and that is required to model switching stations or transmission Loads.

(2) Each TSP and if applicable, Resource Entity, shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) Each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) A description of all transmission circuits that may be connected through breakers or switches; and

(f) Other data necessary to model Transmission Element(s).

(3) To accommodate the Outage Scheduler, the TSP and Resource Entity may define a separate name and Transmission Element for any Electrical Bus that can be physically separated by a manual switch or breaker within a substation.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) To accommodate the Outage Scheduler, the TSP, DCTO, and Resource Entity may define a separate name and Transmission Element for any Electrical Bus that can be physically separated by a manual switch or breaker within a substation.

3.10.7.1.3 Transmission Breakers and Switches

(1) ERCOT's Network Operations Model must include all transmission breakers and switches, the operation of which may cause a change in the flow on transmission lines or Electrical Buses. Breakers and switches may only be connected to defined Electrical Buses.

(2) Each TSP and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Connectivity;

(f) Normal status;

(g) Synchronism check relay phase angle limits that are applied to operator-initiated, non-automated control actions of TSP-owned transmission breakers; and

[NPRR857: Replace item (g) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(g) Synchronism check relay phase angle limits that are applied to operator-initiated, non-automated control actions of TSP-owned or DCTO-owned transmission breakers; and

(h) Other data necessary to model Transmission Element(s).

(3) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the Load should be transferred from one transmission line to another transmission line. ERCOT may employ heuristic rule sets for all manual Load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer Load under line outage conditions. Each TSP and as applicable, Resource Entity, shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the Load should be transferred from one transmission line to another transmission line. ERCOT may employ heuristic rule sets for all manual Load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer Load under line outage conditions. Each TSP and as applicable, each DCTO and Resource Entity, shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-

of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model.

3.10.7.1.4 Transmission and Generation Resource Step-Up Transformers

[NPRR973: Replace the title for Section 3.10.7.1.4 above with the following upon system implementation of PR106:]

3.10.7.1.4 Transmission, Main Power Transformers (MPT) and Generator Step-Up (GSU) Transformers

(1) ERCOT shall model all transformers with a nominal low side (i.e., secondary, not tertiary) voltage above 60 kV.

(2) ERCOT shall model all Generation Resource step-up transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under Load, accept telemetry of the current tap position.

[NPRR973: Replace paragraph (2) above with the following upon system implementation of PR106:]

(2) For Generation Resources, ERCOT shall model all Main Power Transformers (MPTs) and Generator Step-Up (GSU) transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under Load, accept telemetry of the current tap position.

(3) Each TSP and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) Each TSP, DCTO, and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Winding ratings, including Normal Rating, Emergency Rating, 15-Minute Rating, Conductor/Transformer 2-Hour Rating, and Relay Loadability Rating;

(f) Connectivity;

(g) Transformer parameters, including all tap parameters; and

(h) Other data necessary to model Transmission Element(s).

(4) The Resource Entity shall provide parameters for each step-up transformer to ERCOT as part of the Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process. ERCOT shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to establish the proper transformer tap positions (no-load taps) and the equipment owner shall report any changes to ERCOT using the NOMCR process or other ERCOT prescribed means. Each Resource Entity and each TSP shall schedule generation Outages at mutually agreeable times to implement tap position changes when necessary. If mutual agreement cannot be reached, then ERCOT shall decide where to set the tap position to be implemented by the Resource Entity at the next generation Outage, considering expected impact on system security, future Outage plans, and participants. TSPs shall provide ERCOT and Market Participants with notice in accordance with paragraph (4) of 3.10.4, ERCOT Responsibilities, paragraph (4) (except for emergency) prior to the tap position change implementation date.

[NPRR973: Replace paragraph (4) above with the following upon system implementation of PR106:]

(4) The Resource Entity shall provide parameters for each MPT to ERCOT as part of the Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process. ERCOT shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to establish the proper transformer tap positions (no-load taps) and the equipment owner

shall report any changes to ERCOT using the NOMCR process or other ERCOT prescribed means. Each Resource Entity and each TSP shall schedule generation Outages at mutually agreeable times to implement tap position changes when necessary. If mutual agreement cannot be reached, then ERCOT shall decide where to set the tap position to be implemented by the Resource Entity at the next generation Outage, considering expected impact on system security, future Outage plans, and participants. TSPs shall provide ERCOT and Market Participants with notice in accordance with paragraph (4) of Section 3.10.4, ERCOT Responsibilities, (except for emergency) prior to the tap position change implementation date.

(5) ERCOT shall post to the MIS Secure Area information regarding all transformers represented in the Network Operations Model.

3.10.7.1.5 Reactors, Capacitors, and other Reactive Controlled Sources

(1) ERCOT shall model all controlled reactive devices. Each Market Participant shall provide ERCOT with complete information on each device's capabilities and normal switching schema.

(2) Each Market Participant shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Voltage or time switched on;

(f) Voltage or time switched off;

(g) Associated switching device name;

(h) Connectivity;

(i) Nominal voltage and associated capacitance or reactance; and

(j) Other data necessary to model Transmission Element(s).

(3) The ERCOT Operating Guides must include parameters for standard reactor and capacitor switching plans for use in the Network Operations Model. ERCOT shall model the devices under Section 3.10.4, ERCOT Responsibilities, in all applicable ERCOT applications and systems. ERCOT shall provide copies of the switching plan to the

Market Participants via the MIS Secure Area. Any change in TSP guidelines or switching plan must be provided to ERCOT before implementation (except for emergency). Any change in guidelines or switching plan must be provided in accordance with the NOMCR process or other ERCOT-prescribed process.

3.10.7.2 Modeling of Resources and Transmission Loads

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and the non-TSP owned step-up transformers greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

[NPRR973 and NPRR995: Replace applicable portions of paragraph (1) above with the following upon system implementation of PR106 for NPRR973; or upon system implementation for NPRR995:]

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, SOESSs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), and the non-TSP MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

(2) Each Resource Entity representing either a Load Resource or an Aggregate Load Resource (ALR) shall provide ERCOT and, as applicable, its interconnecting DSP and TSP, with information describing each such Resource as specified in Section 3.7.1.2, Load Resource Parameters, and any additional information and telemetry as required by ERCOT, in accordance with the timelines set forth in Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall coordinate the modeling of ALRs with Resource Entities. ERCOT shall coordinate with representatives of the Resource Entity to map Load Resources to their appropriate Load in the Network Operations Model.

(3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting

DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model.

(4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG facilities to their appropriate Load in the Network Operations Model.

[NPRR995: Replace paragraph (4) above with the following upon system implementation:]

(4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) or Settlement Only Distribution Energy Storage System (SODESS) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG or SODESS facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG or SODESS facilities to their appropriate Load in the Network Operations Model.

(5) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility main power transformer.

[NPRR973: Replace paragraph (5) above with the following upon system implementation of PR106:]

(5) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources. The Split Generation Resource

must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility MPT.

(6) ERCOT shall create a DC Tie Resource to represent an equivalent generation injection to represent the flow into the ERCOT Transmission Grid from operation of DC Ties. The actual injection flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Resource output.

(7) TSPs shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(7) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

(8) ERCOT may require TSPs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP shall notify ERCOT if the owner does not comply with the request.

[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(8) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request.

(9) ERCOT shall create a DC Tie Load to represent an equivalent Load withdrawal to represent the flow from the ERCOT Transmission Grid from operation of DC Ties. The actual withdrawal flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Load output.

(10) Each TSP shall also provide information to ERCOT describing automatic Load transfer (rollover) plans and the events that trigger which Loads are switched to other Transmission Elements on detection of Outage of a primary Transmission Element. ERCOT shall accommodate Load rollover plans in the Network Operations Model.

(11) Loads associated with a Generation Resource in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and served through a transformer owned by the Resource Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3.

(12) If the Day-Ahead Market (DAM) determines, in the processing of Outages, that a Load Resource, DGR, or DESR is de-energized in the ERCOT Network Operations Model, the de-energized Resource will be eligible to receive Ancillary Service awards in the DAM, but will not be eligible to receive energy awards in the DAM.

(13) A Resource Entity may aggregate Intermittent Renewable Resource (IRR) generation equipment together to form an IRR (Wind-powered Generation Resource (WGR) or PhotoVoltaic Generation Resource (PVGR)) if the generation equipment is behind the same main power transformer and is the same model and size, and the aggregation does not reduce ERCOT's ability to model pre- and post-contingency conditions. A Resource Entity may also aggregate IRR generation equipment that is not the same model and size together with an existing IRR only if:

(a) The mix of IRR generation equipment models and sizes causes no degradation in the dynamic performance of the IRR represented by the parameters modeled by ERCOT in operational studies and the aggregation of IRR generation equipment does not limit ERCOT's ability to model the ERCOT Transmission Grid and the relevant contingencies required for monitoring pre- and post-contingency system limits and conditions;

(b) The mix of IRR generation equipment is included in the Resource Registration data submitted for the WGR;

(c) All relevant IRR generation equipment data requested by ERCOT is provided;

(d) With the addition of dissimilar IRR generation equipment, the existing IRR shall continue to meet the applicable Protocol performance requirements, including but not limited to Primary Frequency Response, dynamic capability and Reactive Power capability, at the POIB; and

(e) Either:

  (i) No more than the lower of 5% or ten MW aggregate capacity is of IRR generation equipment that is not the same model or size from the other equipment within the existing IRR; or

  (ii) The wind turbines that are not the same model or size meet the following criteria:

    (A) The IRR generation equipment has similar dynamic characteristics to the existing IRR generation equipment, as determined by ERCOT in its sole discretion;

    (B) The MW capability difference of each generator is no more than 10% of each generator's maximum MW rating; and

    (C) For WGRs, the manufacturer's power curves for the wind turbines have a correlation of 0.95 or greater with the other wind turbines within the existing WGR over wind speeds of 0 to 18 m/s.

3.10.7.2.1 Reporting of Demand Response

(1) ERCOT shall post on the ERCOT website by the fifth Business Day after the start of a calendar month a report of the MW of Demand response that is participating in the past month in Emergency Response Service (ERS), Ancillary Service as a Load Resource, or any pilot project permitted by subsection (k) of P.U.C. SUBST. R. 25.361, Electric Reliability Council of Texas (ERCOT). The data shall be aggregated according to the corresponding 2003 ERCOT Congestion Management Zone (CMZ). Data for participation in ERS shall be based on contracted amounts for each type of service for that calendar month. ERCOT shall set out separately MW contracted from both ERS Generators and generators that are participating by offsetting ERS Loads (with aggregated and non-aggregated ERS Generators set forth separately) and MW of ERS Loads. To the extent that a participating generator is not registered with ERCOT, information about the nameplate rating of the generator and the maximum deliverable to the ERCOT Transmission Grid or to serve native load shall be collected through the ERS contracting process. The report shall include these values for each ERS Contract Period broken down by ERS Time Period. Data for Ancillary Services shall be based on the

Ancillary Service Resource Responsibility contained in the Current Operating Plan (COP) as of the start of the Adjustment Period for each Operating Day. ERCOT's posting of Ancillary Service and pilot project participation data shall include the average MW capacity by service type by hour (or by another time period, if a pilot project service is not procured hourly).

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall post on the ERCOT website by the fifth Business Day after the start of a calendar month a report of the MW of Demand response that is participating in the past month in Emergency Response Service (ERS), Ancillary Service as a Load Resource, or any pilot project permitted by subsection (k) of P.U.C. SUBST. R. 25.361, Electric Reliability Council of Texas (ERCOT). The data shall be aggregated according to the corresponding 2003 ERCOT Congestion Management Zone (CMZ). Data for participation in ERS shall be based on contracted amounts for each type of service for that calendar month. ERCOT shall set out separately MW contracted from both ERS Generators and generators that are participating by offsetting ERS Loads (with aggregated and non-aggregated ERS Generators set forth separately) and MW of ERS Loads. To the extent that a participating generator is not registered with ERCOT, information about the nameplate rating of the generator and the maximum deliverable to the ERCOT Transmission Grid or to serve native load shall be collected through the ERS contracting process. The report shall include these values for each ERS Contract Period broken down by ERS Time Period. Data for Ancillary Services shall be based on the Ancillary Service Resource awards in the RTM. ERCOT's posting of Ancillary Service and pilot project participation data shall include the average MW capacity by service type by hour (or by another time period, if a pilot project service is not procured hourly).

3.10.7.2.2 Annual Demand Response Report

(1) On an annual basis, ERCOT shall work with Market Participants to produce a report summarizing aggregate customer counts and MWs enrolled in Demand response in the ERCOT Region pursuant to subsection (e)(5) of P.U.C. SUBST. R. 25.505, Reporting Requirements and the Scarcity Pricing Mechanism in the Electric Reliability Council of Texas Power Region. This report shall be posted to the ERCOT website no later than December 31 of each reporting calendar year. Technical requirements for providing information to ERCOT for the report are located in the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications". ERCOT may, for purposes of this section, associate Entities; however, ERCOT shall not determine Non-Opt-In Entities (NOIEs) to be associated based on their membership in a generation and transmission cooperative or as a result of being a party to a single Load Serving Entity (LSE) registration.

(a) Retail Electric Providers (REPs) in competitive regions of ERCOT shall be ranked in descending order by their average daily consumption for summer (June – September) weekdays excluding holidays. The largest REPs that account for 98% of the total shall be required to participate in the survey for the subsequent calendar year. For purposes of assigning this participation requirement, REPs determined by ERCOT to be associated shall have their consumption aggregated prior to the ranking.

(b) NOIE Transmission and/or Distribution Service Providers (TDSPs) operating in the ERCOT region that register a summer month (June – September) 15-minute interval peak Demand greater than or equal to 100 MW, shall be required to participate in the survey the subsequent calendar year. For purposes of assigning this participation requirement, NOIEs determined by ERCOT to be associated shall have their 15-minute interval peak Demand aggregated prior to the ranking. Participation in the survey shall be the responsibility of either the NOIE TDSP or the NOIE LSE associated with that TDSP based on which entity is responsible for administering Demand response programs within the NOIE TDSP footprint.

(2) By December 31 of each year, ERCOT shall provide advance notice of participation status. To the extent that REPs discontinue participation in the ERCOT market or change associations prior to the snapshot date, ERCOT will send revised notices to REPs affected by such changes no later than August 1 of the survey year. ERCOT shall:

(a) Analyze the summer consumption for all NOIEs and REPs and determine which are required to participate in the Demand response survey for the following year;

(b) Provide advance notice, via email to the Authorized Representative, to all NOIEs and REPs regarding their participation status; and

(c) Provide a list of all REPs or NOIE TDSPs to the Authorized Representative, including all those determined by ERCOT to be associated, to which the participation status applies.

(3) By August 1 of the survey year, ERCOT shall provide official notice of the beginning of the Demand response data collection process. ERCOT shall:

(a) Issue a Market Notice to notify all REPs and NOIEs that the annual Demand response data collection process is beginning. The Market Notice shall make reference to this Protocol section, and shall reiterate specifics of the timeline for the survey process that are to be followed;

(b) Send a reminder email to the Authorized Representative for all REPs, NOIE LSEs and NOIE TDSPs of their participation status. The email shall also contain the list of all REPs or NOIE TDSPs, for which participation status applies. The list shall include all REPs or NOIE TDSPs determined by ERCOT to be associated. This list shall be updated based on any changes in associations that have occurred since the time the advance notice was issued.

(4) By August 15 of the survey year, REPs and NOIEs that are required to participate in that year's survey, and that will have Customers participating in one or more Demand response program as of the snapshot date of September 1 shall reply to ERCOT with the following:

(a) An acknowledgement of the participation requirement;

(b) An indication that they expect to have Customers participating in one or more Demand response programs on the snapshot date of September 1;

(c) A list of contact people and their email address within their organization that should receive copies of communications related to the survey from ERCOT;

(d) Specifically for REPs, an indication as to which of the methods described in the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications" the REP intends to use to submit files to and receive files from ERCOT; and

(e) Specifically for NOIEs, an indication as to whether the NOIE TDSP or the NOIE LSE is responsible for administering the Demand response programs within the NOIE TDSP area.

(5) By August 15 of the survey year, REPs and NOIEs that are required to participate in that year's survey, and that do not plan to have any Customers participating in Demand response programs as of the snapshot date of September 1 shall reply to ERCOT indicating the lack of such participation. REPs and NOIEs that are not required to participate in that year's survey are not required to reply to ERCOT.

(6) By October 15 of the survey year, the REPs participating in that year's survey shall compile the required Electric Service Identifier (ESI ID) participation data in the format specified by the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications", and submit the data to ERCOT.

(7) By October 31 of the survey year, the REPs participating in that year's survey that have reported participation in programs which entail REP-initiated deployments shall compile the required deployment event participation data in the format specified by the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications", and submit the data to ERCOT.

(8) By October 31 of the survey year, the NOIEs participating in that year's survey shall compile the required data in the format specified by the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications", and submit the data to ERCOT.

(9) ERCOT shall validate the submitted reports, and indicate any errors and inconsistencies that require correction to the REP or NOIE, within two Business Days of the submission

in the manner specified in the Other Binding Document titled “Demand Response Data Definitions and Technical Specifications”.

(10) On or before October 31 of the survey year, REPs shall address the errors and inconsistencies and submit corrected reports to ERCOT. ERCOT will notify the Authorized Representative for each REP and/or NOIE when they have achieved the required level of accuracy.

(11) On or before November 7 of the survey year, NOIEs shall address the errors and inconsistencies and submit corrected reports to ERCOT. ERCOT will notify the Authorized Representative for each REP and/or NOIE when they have achieved the required level of accuracy.

(12) Information provided by NOIEs and REPs to meet the above described reporting requirements shall be treated as Protected Information in accordance with Section 1.3, Confidentiality.

3.10.7.3 Modeling of Private Use Networks

(1) ERCOT shall create and use network models describing Private Use Networks according to the following:

(a) A Generation Entity with a Resource located within a Private Use Network shall provide data to ERCOT, for use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network in accordance with Section 3.3.2.1, Information to Be Provided to ERCOT, if it meets any one of the following criteria:

(i) Contains a generator greater than ten MW and is registered with the PUCT according to P.U.C. SUBST. R. 25.109, Registration of Power Generation Companies and Self-Generators, as a power generation company; or

(ii) Is part of a Private Use Network which contains more than one connection to the ERCOT Transmission Grid; or

(iii) Contains generation registered to provide Ancillary Services.

(b) A Generation Entity with an SOTSG shall provide to ERCOT annually, or more often upon change, the following information for ERCOT’s use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network:

(i) Equipment owner(s);

(ii) Equipment operator(s);

(iii) TSP substation name connecting the Private Use Network to the ERCOT System;

(iv) At the request of ERCOT, a description of Transmission Elements within the Private Use Network that may be connected through breakers or switches;

(v) Net energy delivery metering, as required by ERCOT, to and from the Private Use Network and the ERCOT System at the POIB;

(vi) For each individual generator located within the Private Use Network, the gross capacity in MW and its reactive capability curve;

(vii) Maximum and minimum reasonability limits of the Load located within the Private Use Network;

(viii) Outage schedule for each generation unit located within the Private Use Network, updated as changes occur from the annually submitted information; and

(ix) Other interconnection data as required by ERCOT.

(c) Energy delivered to ERCOT from an SOTSG shall be settled in accordance with Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone.

(d) ERCOT shall ensure the Network Operations Model properly models the physical effect of the loss of generators and Transmission Elements on the ERCOT Transmission Grid equipment loading, voltage, and stability.

(e) ERCOT may require the owner or operator of a Private Use Network to provide information to ERCOT and the TSP on Transmission Facilities located within the Private Use Network for use in the Network Operations Model if the information is required to adequately model and determine the security of the ERCOT Transmission Grid, including data to perform loop flow analysis of Private Use Networks.

(f) ERCOT shall review submittals of modeling data from owners or operators of Private Use Networks assure that it will result in correct analysis of ERCOT Transmission Grid security.

3.10.7.4 Remedial Action Schemes, Automatic Mitigation Plans and Remedial Action Plans

(1) All approved Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs) and Remedial Action Plans (RAPs) must be defined in the Network Operations Model where practicable.

(2) Proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs and Resource Entities that own Transmission Facilities included in the RASs or AMPs or RAPs, and shall approve proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) Proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs, DCTOs, and Resource Entities that own Transmission Facilities included in the RASs or AMPs or RAPs, and shall approve proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

(3) ERCOT shall use a NOMCR to model approved RASs, AMPs and RAPs where practicable and include the RASs, AMPs or RAPs modeled in the Network Operations Model in the security analysis. The NOMCR shall include a detailed description of the system conditions required to implement the RASs, AMPs or RAPs. If an approved RAS, AMP, or RAP cannot be modeled, then ERCOT shall develop an alternative method for recognizing the unmodeled RAS, AMP, or RAP in its tools. Execution of RASs, AMPs or RAPs modeled in the Network Operations Model shall be included or assumed in the calculation of LMPs. ERCOT shall provide notification to the market and post on the MIS Secure Area all approved RASs, AMPs and RAPs at least two Business Days before implementation, identifying the date of implementation. The notification to the market shall state whether the approved RAP, AMP, or RAS will be modeled in the Network Operations Model. For RAPs developed in Real-Time, ERCOT shall provide notification to the market as soon as practicable.

3.10.7.5 Telemetry Requirements

(1) The telemetry provided to ERCOT necessary to support the State Estimator must meet the requirements set forth in Section 3.10.9, State Estimator Requirements.

(2) The telemetry provided to ERCOT by each TSP and QSE must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP and QSE. ERCOT shall represent data condition codes from each TSP and QSE in a consistent manner for all applicable ERCOT applications.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) The telemetry provided to ERCOT by each TSP, QSE, or DCTO must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP, DCTO, and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP, DCTO, and QSE. ERCOT shall represent data condition codes from each TSP, DCTO, and QSE in a consistent manner for all applicable ERCOT applications.

(3) Each TSP and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) Each TSP, DCTO, and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, DCTO's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

(4) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Model Loads, and that concern or deficiency is not due to any inadequacy of the State Estimator program, additional telemetry may be requested as described in Section 3.10.7.5.9, ERCOT Requests for Telemetry.

3.10.7.5.1 Continuous Telemetry of the Status of Breakers and Switches

(1) Each TSP and QSE shall be responsible for providing telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource owns, respectively, used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP or Resource Entity switching operations and TSP or Resource Entity personnel.

(3) Each TSP, Resource Entity, or QSE shall update the status of any breaker or switch it owns or is responsible for through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

(b) If the TSP or QSE disputes the request for additional telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

[NPRR857: Replace paragraphs (1) through (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP, DCTO, and QSE shall provide telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource Entity owns, respectively used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP, DCTO, and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP, DCTO, or QSE switching operations and TSP, DCTO, or QSE personnel.

(3) Each TSP, DCTO, and QSE shall update the status of any breaker or switch it owns or its Resource Entity owns, respectively, through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP, DCTO, or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP, DCTO, or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP, DCTO, or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

(b) If the TSP or associated QSE disputes the request for additional telemetry it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

(5) ERCOT shall measure TSP and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) ERCOT shall measure TSP, DCTO, and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

(6) Unless there is an Emergency Condition, TSPs and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

[NPRR857: Replace paragraph (6) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(6) Unless there is an Emergency Condition, TSPs, DCTOs, and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs, DCTOs, and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the

device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP, DCTO, or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

(8) ERCOT shall establish a system that provides alarms to ERCOT Operators when there is a change in status of any monitored transmission breaker or switch, and an indication of whether the device change of status was planned in the Outage Scheduler. ERCOT Operators shall monitor any changes in status not only for reliability of operations, but also for accuracy and impact on the operation of the SCED functions and subsequent potential for calculation of inaccurate LMPs.

(9) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources, shall provide ERCOT with telemetry of the actual generator breakers and switches continuously providing ERCOT with the status of the individual Split Generation Resource.

3.10.7.5.2 Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows

(1) Each TSP and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State

Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP, DCTO, and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

(2) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, and Distribution Generation Resources, and Distribution Energy Storage Resources, shall provide ERCOT with telemetry of the actual equivalent generator injection of its Split Generation Resource and the Master QSE shall provide telemetry in accordance with Section 6.5.5.2, Operational Data Requirements, on a total Generation Resource basis. ERCOT shall calculate the sum of each QSE’s telemetry on a Split Generation Resource and compare the sum to the telemetry for the total Generation Resource. ERCOT shall notify each QSE representing a Split Generation Resource of any errors in telemetry detected by the State Estimator.

(3) Each TSP and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) Each TSP, DCTO, and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

(4) The accuracy of the State Estimator is critical to successful market operations. For this reason it is a critical objective for ERCOT to maintain reasonable and accurate results of the State Estimator. ERCOT shall use all reasonable efforts to achieve that objective, including the provision of legitimate constraints used in calculating LMPs.

(5) Each TSP, QSE and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP or QSE and suggest actions that the TSP or QSE could take to correct the failure. Within 30 days, the TSP or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) Each TSP, DCTO, QSE, and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a

connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP, DCTO, or QSE and suggest actions that the TSP, DCTO, or QSE could take to correct the failure. Within 30 days, the TSP, DCTO, or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

(6) ERCOT shall implement a study mode version of the State Estimator with special tools designed for troubleshooting and tuning purposes that can be used independently of any other ERCOT process that is dependent on the Real-Time State Estimator. ERCOT shall implement a process to recognize inaccurate State Estimator results and shall create and implement alternative Real-Time LMP calculation processes for use when inaccurate results are detected. ERCOT must be guided in this by Section 3.10.9.

(7) ERCOT shall establish a system to provide overload and over/under limit alarming on all Transmission Elements monitored as constraints in the LMP models.

(8) Each TSP shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with Voltage Set Point instructions, and then update the designation as necessary in the Network Operations Model by submitting a NOMCR. Each TSP shall telemeter this POI kV bus measurement to ERCOT. If the TSP cannot provide a kV bus measurement at the POI, the TSP may propose an alternate location subject to ERCOT approval.

[NPRR1098: Insert paragraph (9) below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(9) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support, shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with target voltage instructions, and then update the designation

as necessary in the Network Operations Model by submitting a NOMCR. Each TO shall telemeter this POI kV bus measurement to ERCOT via ICCP and the DCTO via telemetry. If the TO cannot provide a kV bus measurement at the POI, the TO may propose an alternate location subject to ERCOT approval.

3.10.7.5.3 Required Telemetry of Voltage and Power Flow

(1) QSEs, Resource Entities and TSPs as indicated in each subsection below shall provide power operation data to ERCOT, including, but not limited to:

- (a) Real-Time generation data from QSEs;
- (b) Planned and Forced Outage information from QSEs;
- (c) Network data from TSPs and QSEs , including:
    - (i) Breaker and line switch status of all ERCOT Transmission Grid devices;
    - (ii) Line flow MW and MVAr;
    - (iii) Breaker and switch status connected to any Resource;
    - (iv) Transmission Facility voltages; and
    - (v) Transformer MW, MVAr and tap;
- (d) Real-Time generation and Load Resource meter data from QSEs;
- (e) Real-Time generation meter splitting signal from QSEs;
- (f) Transmission Facility Planned and Forced Outage information from TSPs;
- (g) Network transmission data (model and constraints) from TSPs; and
- (h) Resource modeling data, including any Resource owned transmission equipment data from Resource entity; and
- (i) Dynamic schedules from QSEs.

(2) Real-Time data will be provided to ERCOT at the same scan rate as the TSP, Resource Entity, or QSE obtains the data from telemetry unless ERCOT requests a slower rate.

3.10.7.5.4 General Telemetry Performance Criteria

(1) The following criteria will apply to telemetry provided to ERCOT. Performance is posted on the MIS Secure Area in accordance with Nodal Operating Guide Section 9, Monitoring Programs:

(a) Each TSP shall maintain the sum of flows into any telemetered bus it owns or is responsible for less than the greater of five MW or 5% of the largest normal line rating at each bus.

(b) Each TSP and QSE shall provide data to ERCOT that meets the following availability:

(i) 92% of all telemetry provided to ERCOT must achieve a quarterly availability of 80%. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with a Valid, Manual, or Calculated quality code at the scheduled periodicity. Quality codes are defined in Section 3.10.7.5.8.1, Data Quality Codes.

(ii) TSPs shall make reasonable efforts to obtain data from Customers associated with new Customer-owned substations to meet this requirement or obtain agreement from ERCOT that these Customers have entered into arrangements with ERCOT to provide this data to ERCOT. If the data cannot be obtained under either of these methods, ERCOT shall report such case to the IMM.

(c) Exceptions to the general telemetry performance criteria may be made, at ERCOT's sole discretion, for data points not significant in the solution of the State Estimator or required for the reliable operation on the ERCOT Transmission Grid. Examples of such data points include but are not limited to:

(i) A substation with no more than two transmission lines and less than ten MW of peak Load;

(ii) Connection of Loads along a continuous, non-branching circuit that may be combined for telemetry purposes; and

(iii) Substations connected radially to the ERCOT Transmission Grid.

(d) During a Force Majeure Event, ERCOT may suspend requirements until normal operations have resumed.

3.10.7.5.5 Supplemental Telemetry Performance Criteria

(1) ERCOT shall identify specific MW/MVAr telemetry pairs, not exceeding 10% of the Transmission Elements within the ERCOT System, and the 20 station voltage points that

are most important to reliability, system observability or support of State Estimator performance, or are of a commercial market concern.

(2) The important telemetry points identified pursuant to this Section must meet more stringent criteria for accuracy and availability where specifically addressed. ERCOT shall review this list annually. ERCOT shall publish the list of important telemetry points quarterly on the MIS Secure Area.

(3) ERCOT shall use the following criteria to identify the important telemetry points:

(a) Loss of a telemetry point that results in the inability of ERCOT to monitor loading on a transmission line operated at 345 kV or above.

(b) Loss of a telemetry point that results in the inability of ERCOT to monitor loading on a 345/138 kV autotransformer.

(c) Loss of a telemetry point that results in the inability of ERCOT to monitor the loading on Transmission Facilities designated as important to transmission reliability by ERCOT.

(d) Telemetry necessary to monitor Transmission Elements identified as causing 80% of all congestion cost in the year for which the most recent data is available.

(e) Telemetry necessary to monitor the bus voltages at the 20 most important station voltage points.

(4) Each TSP and QSE shall provide data to ERCOT such that 92% of the important telemetry points identified achieve a quarterly availability of 90%. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with Valid, Manual, or Calculated quality codes at the scheduled periodicity. Quality codes are defined in Section 3.10.7.5.8.1, Data Quality Codes.

3.10.7.5.6 TSP/QSE Telemetry Restoration

(1) Telemetered data shall be provided continuously. Real-Time data restoration shall comply with Nodal Operating Guide Sections 7.3.3, Data from WAN Participants to ERCOT, and 7.3.4, Resolving Real-Time Data Issues that affect ERCOT Network Security Analysis.

(2) Some data may be more essential to the State Estimator solution. ERCOT shall inform the TSP or QSE if, in the sole opinion of ERCOT, a data item is essential and needs to be repaired as quickly as possible. QSEs and TSPs shall make repair procedures and records available to ERCOT upon request. When ERCOT notifies a data provider that a data element is providing telemetry data inconsistent with surrounding measurements, the provider shall, within 30 days, do one of the following:

(a) Calibrate or repair the failing equipment;

(b) Request an outage to schedule calibration or repair of the failing equipment;

(c) Provide ERCOT with a plan to re-calibrate or repair the equipment in a reasonable time frame; or

(d) Provide ERCOT with engineering analysis proving the data element is providing accuracy within its specifications.

(3) Before ERCOT requests review or re-calibration of a problem piece of equipment, it shall discuss the problem with the data provider to attempt to arrive at a consensus decision on the most appropriate action.

3.10.7.5.7 Calibration, Quality Checking, and Testing

(1) It is the responsibility of the equipment owner to insure that calibration, testing, and other routine maintenance of equipment is done on a timely basis, and that accuracy meets or exceeds the requirements specified in this Section 3.10.7.5, Telemetry Requirements, for both the overall system and for individual equipment where detailed herein. Coordination with ERCOT of outages required for these activities is also the responsibility of the owner.

3.10.7.5.8 Inter-Control Center Communications Protocol (ICCP) Links

3.10.7.5.8.1 Data Quality Codes

(1) Market Participants shall provide documentation to ERCOT describing their native system quality codes and defining the conversion of their quality codes into the ERCOT-defined quality codes.

(2) Statuses and analogs telemetered to ERCOT shall be identified with the following quality codes:

(a) Valid – Represents an analog or status the TSP or QSE considers valid.

(b) Manual – Represents an analog or status entered manually at the Market Participant (i.e., not received from the field electronically).

(c) Calculated – Represents an analog point that the TSP or QSE calculates.

(d) Suspect – Represents an analog or status of which the TSP or QSE is unsure of the validity

(e) Invalid – Represents an analog or status that the Market Participant has identified as out of reasonability limits.

(f) Com_fail – Informs ERCOT that due to communications failure, the analog or status provided ERCOT is not current.

3.10.7.5.8.2 Reliability of ICCP Associations

(1) Each Market Participant using ICCP associations must achieve a monthly availability of 98%, excluding approved Planned Outages. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of configured data at the scheduled periodicity. To meet the 98% monthly availability, each Market Participant should establish a process to coordinate downtime for ICCP associations and database maintenance. High availability configuration as allowed by the ERCOT Nodal ICCP Communication Handbook should be treated as a single association to achieve this availability measure.

3.10.7.5.9 ERCOT Requests for Telemetry

(1) ERCOT is required to protect Transmission Facilities operated at 60 kV or above from damage. To do this, ERCOT may request that additional telemetry be installed, while attempting to minimize adding equipment to as few locations as practicable.

(2) ERCOT may request additional telemetry when it determines that network observability or the measurement redundancy is not adequate to produce acceptable State Estimator results.

(3) Prior to making a request for additional telemetry, ERCOT shall provide evidence supporting a congestion or reliability problem requiring additional observability and define expected improvements in ERCOT System observability needed. If the request is for telemetry additions at more than one location, ERCOT shall prioritize the requested additions.

(4) No later than 60 days after receipt of a request for additional telemetry, the TSP or QSE shall:

(a) Accept ERCOT’s request for additional telemetry and notify ERCOT of the implementation schedule, which shall be no later than 18 months following the receipt of the request for additional telemetry;

(b) Provide an alternative proposal to ERCOT, for implementation no later than 18 months following the receipt of the request for additional telemetry, that meets the requirements described by ERCOT;

(c) Propose a normal topology change by changing normal status of switch(es) in the area that would eliminate the security violations that are ERCOT’s concern;

(d) Indicate that the requested telemetry point is at a location where the TSP or QSE does not have the authority to install the requested telemetry. For points on privately owned facilities connected to the ERCOT Transmission Grid, an attempt will be made to facilitate ERCOT's telemetry request;

(e) Provide ERCOT an analysis of the cost to comply with the request, so that, ERCOT can perform a cost justification with respect to the LMP market; or

(f) If the TSP or QSE disagrees with the request, the TSP or QSE may request that ERCOT withdraw its request for additional telemetry.

[NPRR979: Replace paragraph (4) above with the following upon system implementation of NPRR857:]

(4) No later than 60 days after receipt of a request for additional telemetry, the TSP, DCTO, or QSE shall:

(a) Accept ERCOT's request for additional telemetry and notify ERCOT of the implementation schedule, which shall be no later than 18 months following the receipt of the request for additional telemetry;

(b) Provide an alternative proposal to ERCOT, for implementation no later than 18 months following the receipt of the request for additional telemetry, that meets the requirements described by ERCOT;

(c) Propose a normal topology change by changing normal status of switch(es) in the area that would eliminate the security violations that are ERCOT's concern;

(d) Indicate that the requested telemetry point is at a location where the TSP, DCTO, or QSE does not have the authority to install the requested telemetry. For points on privately owned facilities connected to the ERCOT Transmission Grid, an attempt will be made to facilitate ERCOT's telemetry request;

(e) Provide ERCOT an analysis of the cost to comply with the request, so that, ERCOT can perform a cost justification with respect to the LMP market; or

(f) If the TSP, DCTO, or QSE disagrees with the request, the TSP, DCTO, or QSE may request that ERCOT withdraw its request for additional telemetry.

(5) If ERCOT rejects an alternative proposal pursuant to paragraph (4)(b), (c), or (f) above, the TSP or QSE may appeal the original request to TAC within 30 days of receiving notice of ERCOT's rejection. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP or QSE is not required to provide telemetry measurements from a location not owned by that TSP or QSE if the location owner does not grant access to the TSP or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM.

[NPRR979: Replace paragraph (5) above with the following upon system implementation of NPRR857:]

(5) If ERCOT rejects an alternative proposal pursuant to paragraph (4)(b), (c), or (f) above, the TSP, DCTO, or QSE may appeal the original request to TAC within 30 days of receiving notice of ERCOT’s rejection. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP, DCTO, or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP, DCTO, or QSE is not required to provide telemetry measurements from a location not owned by that TSP, DCTO, or QSE if the location owner does not grant access to the TSP, DCTO, or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM.

3.10.7.5.10 ERCOT Requests for Redundant Telemetry

(1) ERCOT shall maintain redundancy on monitored non-Load substations.

(2) ERCOT shall identify new telemetry required to maintain N-1 observability on monitored non-Load substations. The following conditions shall be used to determine what additional telemetry is required:

(a) Inability of ERCOT to monitor loading on a transmission line operated at 345 kV or above.

(b) Inability of ERCOT to monitor loading on a 345/138 kV autotransformer.

(c) Inability of ERCOT to monitor loading on Transmission Facilities designated as important to transmission reliability by ERCOT.

(3) ERCOT may request additional MW, MVAr and voltage telemetry to make these measurements redundant. In this request, ERCOT shall identify these measurements, and the contingency/overload condition and the unit dispatch that makes this a concern. If the request is for telemetry at multiple locations, ERCOT shall prioritize the requested additions.

(4) Except as provided in paragraph (5) below, no later than 60 days after receipt of a request for additional telemetry, a TSP or QSE shall:

(a) Accept ERCOT’s request for additional telemetry and notify ERCOT of the implementation schedule, which shall be no later than 18 months following the receipt of the request for additional telemetry; or

(b) Propose an alternative solution that will serve the same purpose as the ERCOT identified telemetry additions, with a proposed implementation no later than 18 months following the receipt of the request for additional telemetry;

(5) In cases where the request is based on the availability rate of an existing telemetry point, no later than 30 days after receipt of a request for additional telemetry, the TSP or QSE shall:

(a) Provide a plan to improve the availability rate of the identified telemetry to meet the requirements of paragraph (1)(b)(i) of Section 3.10.7.5.4, General Telemetry Performance Criteria, and paragraph (3) of Section 3.10.7.5.5, Supplemental Telemetry Performance Criteria;

(b) Provide documentation for why the improvements set forth in paragraph (a) above cannot be accomplished;

(c) Identify and propose a schedule of equipment installations or maintenance to be completed no later 18 months following the receipt of the request for additional telemetry that would, as a result, change the classification of the Transmission Element identified by ERCOT; or

(d) Indicate that the facility for which telemetry is being requested is not owned or covered by an agreement that allows the requested party to install the additional telemetry.

(6) If ERCOT rejects an alternative solution proposed pursuant to paragraph (4) or (5) above, the TSP or QSE may appeal the original request to TAC within 30 days of receiving notice of ERCOT's rejection. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP or QSE is not required to provide telemetry measurements from a location not owned by that TSP or QSE if the location owner does not grant access to the TSP or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM.

3.10.7.6 Use of Generic Transmission Constraints and Generic Transmission Limits

(1) For the sole purpose of creating transmission flow constraints between areas of the ERCOT Transmission Grid in ERCOT applications that are unable to recognize non-thermal operating limits (such as system stability limits and voltage limits on Electrical Buses), ERCOT may create new Generic Transmission Constraints (GTCs) or modify existing GTCs for use in reliability and market analysis. GTCs created or modified as described in this Section shall be used in the SCED application. ERCOT shall not use GTCs in ERCOT applications to replace other constraints already capable of being directly modeled in the SCED application.

(2) During the ERCOT quarterly stability assessment, performed pursuant to Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if ERCOT determines a GTC is necessary for a new Generation Resource and SOTSG due to localized stability issues associated with the output of the interconnecting Generation Resource or SOTSG, the GTL for the GTC shall be set to the lowest non-zero limit for all system conditions outside those in which the limit is zero.

(3) Except as provided in paragraph (6) below, ERCOT shall post a description of each new or modified GTC to the MIS Secure Area as soon as possible, but no later than the day prior to the GTC or GTC modification becoming effective in any ERCOT application. Posting of each new or modified GTC shall include:

(a) The description of the new or modified GTC including the GTL or description of the data and studies used to calculate the GTL associated with each new or modified GTC;

(b) The effective date of the new or modified GTC;

(c) The identity of all constrained Transmission Elements that make up the GTC, including the defined interface where applicable; and

(d) Detailed information on the development of each GTC, including the defined constraint or interface where applicable; and data and studies used for development of each new or modified GTC, including the GTL associated with each new or modified GTC. This information shall be redacted or omitted to protect the confidentiality of certain stability-related GTCs.

(4) Market Participants may review and comment on each new or modified GTC. Within seven days following receipt of any comments, ERCOT shall post the comments to the MIS Secure Area as part of the information related to the subject GTC. ERCOT shall review any comments and may modify any part of a given GTC in response to any comments received.

(5) Anticipated GTLs, except those determined pursuant to paragraph (6) below, shall be posted to the MIS Secure Area no later than one day before the Operating Day.

(6) If an unexpected change to ERCOT System conditions requires the creation of a new GTC or the modification of an existing GTC to manage ERCOT System reliability, and the GTC has not been posted pursuant to paragraph (3) above, ERCOT shall issue an Operating Condition Notice (OCN) and post on the MIS Secure Area the new or modified GTC and its associated GTL(s), including the detailed information described in paragraphs (3) and (5) above. ERCOT shall include an explanation regarding why it did not post the GTC or modification on the previous day.

(7) No later than 180 days after the effective date of a new GTC, ERCOT shall post a report listing alternatives for exiting the GTC to the MIS Secure Area. The listed alternatives may include but are not limited to the implementation or modification of a RAS or a transmission improvement project.

3.10.7.7 DC Tie Limits

(1) ERCOT shall post DC Tie limits for each hour of the Operating Day to the MIS Secure Area no later than 0600 in the Day-Ahead before the Operating Day. ERCOT may update these limits as system conditions change.

(2) DC Tie limits shall be based on expected system conditions, including Outages, for each hour of the Operating Day and shall be calculated as the lower of the physical capacity of the DC Tie, the amount of DC Tie import and export that could flow without resulting in transmission security violations that would not be resolved by SCED, or, for the DC Ties with Mexico, any limits supplied by the Mexican system operator. In setting these limits for a given hour, ERCOT shall assume that any Generation Resource shown to be available in its COP will be self-committed or committed at the appropriate time through the Reliability Unit Commitment (RUC) process to resolve any transmission constraints resulting from DC Tie Schedules. DC Tie Schedules are subject to the actual availability of that generation at the time the Generation Resource is needed, as well as other system conditions.

[NPRR825: Replace Section 3.10.7.7 above with the following upon system implementation:]

3.10.7.7 DC Tie Advisory Limits

(1) Every hour, ERCOT shall post DC Tie advisory limits for each hour of the next 48 hours to the MIS Secure Area. ERCOT may update these limits as system conditions change. Any updated DC Tie advisory limits shall be posted to the MIS Secure Area as soon as practicable.

(2) DC Tie advisory limits shall be based on expected, or actual system conditions, including Outages, for each hour of the Operating Day and shall be calculated as the lower of the available physical capacity of the DC Tie, the amount of DC Tie import and export that could flow without resulting in transmission security violations that would not be resolved by SCED, or, for the DC Ties with Mexico, any limits supplied by the Mexican system operator. In setting these limits for a given hour, ERCOT shall assume that any Generation Resource shown to be available in its COP for a given hour will be self-committed or committed at the appropriate time through the Reliability Unit Commitment (RUC) process to resolve any transmission security violations resulting from DC Tie Schedules. DC Tie Schedules are subject to the actual availability of that generation at the time the Generation Resource is needed, as well as other system conditions.

3.10.8 Dynamic Ratings

(1) ERCOT shall use Dynamic Ratings, where available, in the Network Operations Model and the CRR Network Models.

(2) ERCOT shall use Dynamic Ratings in place of the Normal Rating, Emergency Rating and 15-Minute Rating as applicable as provided under paragraphs (a) or (b) below for Transmission Elements established in the Network Operations Model.

(a) A TSP may provide Dynamic Ratings via ICCP for implementation in the next Operating Hour. ERCOT shall use the Dynamic Ratings in its Supervisory

Control and Data Acquisition (SCADA) alarming, Real Time Security Analysis, and SCED process. In addition, the TSP shall provide ERCOT with a table of equipment rating versus temperature for use in operational planning studies.

(b) Each TSP may alternatively elect to provide ERCOT with a table of equipment rating versus temperature and a temperature value in Real-Time for each Weather Zone in which the Transmission Element is located. ERCOT shall apply the table of temperature and rating relationships and ERCOT's current temperature measurements to determine the rating of each such designated piece of equipment for each Operating Hour. ERCOT shall use the TSP-provided table in operational planning studies.

(3) Each Operating Hour, ERCOT shall post on the MIS Secure Area updated Dynamic Ratings adjusted for the current temperature.

(4) ERCOT may request that a TSP submit temperature-adjusted ratings on Transmission Elements that ERCOT identifies as contributing to significant congestion costs. Each TSP shall provide the additional ratings within two months of such a request using one of the two mechanisms for supplying temperature-adjusted ratings identified above. Ratings for Transmission Elements operated by multiple TSPs must be supplied by each TSP that has control. ERCOT shall use the most limiting rating and report the circumstance to the IMM.

3.10.8.1 Dynamic Ratings Delivered via ICCP

(1) The TSP shall supply the following, via ICCP, updated at least every ten minutes:

(a) Normal Rating; and

(b) Optionally Emergency Rating and/or 15-Minute Rating (required when Emergency Rating is provided).

(2) ERCOT shall link each provided line rating with the ERCOT Network Operations Model and implement the ratings for the next Operating Hour. ERCOT shall use the Dynamic Ratings in its SCADA alarming, real-time Security Analysis, and SCED process. When the telemetry is not operational, ERCOT shall use a temperature appropriate for current conditions, and employ the required Dynamic Rating lookup table to determine the appropriate rating.

3.10.8.2 Dynamic Ratings Delivered via Static Table and Telemetered Temperature

(1) ERCOT shall define a set of tables implementing the dynamic characteristics provided by the TSP(s) and as applicable, Resource Entity(s), of selected transmission lines, including:

(a) Line ID;

(b) From station;

(c) To station;

(d) Weather Zone(s);

(e) TSP(s) and Resource Entity(s); and

(f) Each of the three ratings: Normal Rating, Emergency Rating, and 15-Minute Rating.

(2) If a TSP is providing a current temperature for each applicable Weather Zone through SCADA telemetry then ERCOT shall determine the appropriate rating based upon the telemetered temperature, and adjust the Normal Rating, Emergency Rating, and 15-Minute Rating within five minutes of receipt for the next Operating Hour. ERCOT shall use the Dynamic Ratings in its SCADA alarming, real-time Security Analysis, and SCED process.

3.10.8.3 Dynamic Rating Network Operations Model Change Requests

(1) ERCOT shall use the NOMCR process by which TSPs provide electronically to ERCOT the dynamic rating table described in Section 3.10.8.2, Dynamic Ratings Delivered via Static Table and Telemetered Temperature.

3.10.8.4 ERCOT Responsibilities Related to Dynamic Ratings

(1) ERCOT shall provide a system to accept and implement Dynamic Ratings or temperatures to be applied to rating tables for each hour in the Day-Ahead and in the Operating Hour. ERCOT shall also:

(a) Provide software and processes that allow secure access for TSPs and Market Participants and that maintains a log of data provided and the actions of the TSP and ERCOT, to implement the Dynamic Ratings as described above;

(b) Use Dynamic Ratings for alarming, compliance with ERCOT and NERC requirements, and SCED purposes in both Real-Time operations and operational planning;

(c) Approve or reject the new Dynamic Rating request within 24 hours of receipt;

(d) Post Dynamic Ratings approved by ERCOT for each planned production load of the Network Operations Model on the MIS Secure Area. The posting will include the Transmission Element name, approved thermal rating limits, and the planned effective date; and

(e) Implement the approved Dynamic Rating automatically within 24 hours of approval.

(2) ERCOT shall provide a system to implement Dynamic Ratings and to obtain monthly expected ambient air temperatures to be applied to rating tables for the CRR Network Models. Temperatures applied to the rating tables shall be determined using the same method as described in item (3)(f) of Section 7.5.5.4, Simultaneous Feasibility Test. Transmission Elements that have Dynamic Ratings implemented in the Network Operations Model must have Dynamic Ratings in the CRR Network Models.

(3) ERCOT shall identify additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through Dynamic Rating and request such Dynamic Ratings from the associated TSP. ERCOT shall post annually the list of the Transmission Elements and identify if the TSP has agreed to provide the rating on the MIS Secure Area.

3.10.8.5 Transmission Service Provider Responsibilities Related to Dynamic Ratings

(1) Each TSP shall:

(a) Provide ERCOT with tables of ratings for different ambient temperatures for Transmission Elements, as requested by ERCOT.

(b) Submit within two months a temperature adjusted rating table when a request is received from ERCOT unless multiple requests are made by ERCOT within the two-month period or unusual circumstances prevent the request from being accommodated in a timely fashion. Such circumstances must be explained to ERCOT in writing and must be posted by ERCOT on the MIS Secure Area within five Business Days of receipt.

(c) Provide Real-Time temperatures for each Weather Zone in which the TSP has existing dynamically rated transmission equipment, or alternatively provide rating updates for each temperature-adjusted line rating updated at least once every ten minutes.

3.10.9 State Estimator Requirements

(1) The appropriate TAC subcommittee shall coordinate with Market Participants to ensure a common understanding of the level of State Estimator performance required to enable LMP calculation and address the State Estimator’s ability to detect, correct, or otherwise accommodate communications system failures, failed data points, stale data condition codes, and missing or inaccurate measurements to the extent these capabilities contribute to LMP accuracy and State Estimator performance or as needed to meet reliability requirements.

3.10.9.1 Considerations for State Estimator Requirements

(1) In maintaining the State Estimator requirements, the following may be considered:

(a) Desired confidence levels of State Estimator results;

(b) Measurement requirements to estimate power injections and withdrawals at transmission voltage Electrical Buses defined in the SCED transmission model, which may provide for variations in criteria based on:

  (i) The number of Transmission Elements connected to a given transmission voltage Electrical Bus;

  (ii) The peak demand of the Load connected to a transmission voltage Electrical Bus;

  (iii) The total of Resource capacity connected to a transmission voltage Electrical Bus;

  (iv) The nominal transmission voltage level of an Electrical Bus;

  (v) The number of Electrical Buses with injections or withdrawals along a circuit between currently monitored transmission voltage Electrical Bus;

  (vi) Connection of Loads along a continuous, non-branching circuit that may be combined for modeling purposes;

  (vii) The quantity of Load at an Electrical Bus that may have its connection to the transmission system automatically transferred to an Electrical Bus other than the one to which it is normally connected (rollover operation);

  (vii) Electrical proximity to more than one Resource Node;

  (viii) Degree or quality of continued observability following the loss of telemetry measurements resulting from a common mode failure of telemetry-related equipment (*i.e.*, an N-1 telemetry condition); and

  (ix) Other parameters or circumstances, as appropriate;

(c) Sensitivity of State Estimator results with respect to variations in input parameters;

(d) Reasonable safeguards to assure State Estimator results are calculated on a non-discriminatory basis; and

(e) Other parameters as deemed appropriate.

3.10.9.2 State Estimator Data

(1) ERCOT uses a State Estimator to produce Load flow base cases, which are used to analyze the reliability of the ERCOT Transmission Grid. Accurate and redundant telemetry and an accurate transmission power system model are required by the State Estimator in order to produce an optimal estimation of the transmission power system

state. State Estimator results are used in contingency analysis, congestion management, and other network analysis Real-Time sequence functions.

3.10.9.3 Telemetry Status and Analog Measurements Data

(1) Good telemetry status and analog measurements data for the transmission power system together with an accurate model of the ERCOT System are processed by the State Estimator to provide an optimal estimate of the ERCOT System state at a given point in time while filtering minor measurement errors and detecting gross errors. The quality and availability of telemetry provided to ERCOT is important to the performance of the ERCOT State Estimator.

(2) Telemetry is not needed at every node of the ERCOT System to arrive at a good estimate of the ERCOT System's state. State Estimator performance must meet the performance requirements set forth in Section 3.10.9.4, State Estimator Performance Requirements, unless otherwise provided for in the Operating Guides.

(3) Beyond general telemetry performance criteria there are more stringent criteria needed at locations where state estimates are critically important, including, but not limited to, locations where reliability, security, and market impacts are of heightened concern.

3.10.9.4 State Estimator Performance Requirements

(1) The State Estimator shall converge 98% of runs during a one month period.

(2) For MW flows on Transmission Elements identified by ERCOT as causing 80% of congestion costs in the latest year for which data is available, the residual difference between State Estimator results and power flow results shall be less than 3% of the associated element Emergency Rating on at least 95% of samples measured in a one month period.

(3) For Transmission Elements identified by ERCOT as causing 80% of all congestion costs in the latest year for which data is available, the difference between the telemetry value (MW) and the State Estimator value (MW) shall be less than 3% of the associated element Emergency Rating on at least 95% of samples measured in a one month period.

(4) For the 20 most important station voltage points, as designated by ERCOT and approved by ROS, the telemetered voltage minus State Estimator voltage shall be within 2% of the telemetered voltage measurement for at least 95% of samples measured during a one month period.

(5) For all Transmission Elements 100 kV and above, the difference between the State Estimator solution (MW) and the SCADA measurement will be less than ten MW or 10% of the associated Emergency Rating (whichever is greater) on 99.5% of samples measured during a one month period. ERCOT shall report all equipment failing this test

to the associated TSP who shall repair such equipment no later than ten days following detection by ERCOT.

(6) ERCOT shall post the State Estimator performance requirements contained in this Section on the MIS Secure Area.

3.10.9.5 ERCOT Directives

(1) ERCOT shall work with the TSP or QSE to resolve telemetry and/or model problems in accordance with telemetry requirements prior to directing additional equipment.

(2) In the event of failure to meet the requirements in paragraphs (2) or (3) of Section 3.10.9.4, State Estimator Performance Requirements, ERCOT may direct additional telemetry to be installed on elements contributing most to 80% of congestion costs for the latest year for which data is available. If the TSP or QSE disputes the request for additional telemetry, pursuant to paragraph (4) of Section 3.10.7.5.9, ERCOT Requests for Telemetry, the TSP or QSE may provide an alternative proposal.

(3) ERCOT shall enforce the requirements of paragraph (5) of Section 3.10.7.5.2, Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows, by alarming any sum of flow around a bus that is more than (a) 5% of the largest normal line rating connected to the bus, or (b) five MW, whichever is greater, and requesting that the applicable TSP or QSE correct the failure.

(4) ERCOT shall consider the quality codes sent by the data provider in determining how confidence factors are assigned for the data to be used in the State Estimator. Valid and manual quality codes as defined in Section 3.10.7.5.8.1, Data Quality Codes, shall be considered as good quality. Quality codes sent as not good quality shall be considered at a lower confidence.

3.10.9.6 Telemetry and State Estimator Performance Monitoring

(1) ERCOT shall monitor the performance of the State Estimator, Network Security Analysis, SCED, and LMP Calculator. ERCOT shall post a monthly report of these items on the MIS Secure Area. ERCOT shall notify affected TSPs and QSEs of any lapses of observability of the transmission system.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT shall monitor the performance of the State Estimator, Network Security Analysis, SCED, and LMP Calculator. ERCOT shall post a monthly report of these items on the MIS Secure Area. ERCOT shall notify affected TSPs, QSEs, or DCTOs of any lapses of observability of the transmission system.

3.11 Transmission Planning

3.11.1 Overview

(1) Project endorsement through the ERCOT regional planning process is intended to support, to the extent applicable, a finding by the Public Utility Commission of Texas (PUCT) that a project is necessary for the service, accommodation, convenience, or safety of the public within the meaning of Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 37.056 (Vernon 1998 and Supp. 2007) (PURA) and P.U.C. SUBST. R. 25.101, Certification Criteria.

3.11.2 Planning Criteria

(1) ERCOT and Transmission Service Providers (TSPs) shall evaluate the need for transmission system improvements and shall evaluate the relative value of alternative improvements based on established technical and economic criteria.

(2) The technical reliability criteria are established by the Planning Guide, Operating Guides, and the North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT and TSPs shall strongly endeavor to meet these criteria, identify current and future violations thereof and initiate solutions necessary to ensure continual compliance.

(3) ERCOT shall attempt to meet these reliability criteria as economically as possible and shall actively study the need for economic projects to meet this goal.

(4) For economic projects, the net economic benefit of a proposed project, or set of projects, will be assessed over the project's life based on the net societal benefit that is reasonably expected to accrue from the project. The project will be recommended if it is reasonably expected to result in positive net societal benefits.

(5) To determine the societal benefit of a proposed project, the revenue requirement of the capital cost of the project is compared to the expected savings in system production costs resulting from the project over the expected life of the project. Indirect benefits and costs associated with the project should be considered as well, where appropriate. The current set of financial assumptions upon which the revenue requirement calculations is based will be reviewed annually, updated as necessary by ERCOT, and posted on the Market Information System (MIS) Secure Area. The expected production costs are based on a chronological simulation of the security-constrained unit commitment and economic dispatch of the generators connected to the ERCOT Transmission Grid to serve the

expected ERCOT System Load over the planning horizon. This market simulation is intended to provide a reasonable representation of how the ERCOT System is expected to be operated over the simulated time period. From a practical standpoint, it is not feasible to perform this production cost simulation for the entire 30 to 40 year expected life of the project. Therefore, the production costs are projected over the period for which a simulation is feasible and a qualitative assessment is made of whether the factors driving the production cost savings due to the project can reasonably be expected to continue. If so, the levelized ERCOT-wide annual production cost savings over the period for which the simulation is feasible is calculated and compared to the first year annual revenue requirement of the transmission project. If this production cost savings equals or exceeds this annual revenue requirement for the project, the project is economic from a societal perspective and will be recommended.

(6) Other indicators based on analyses of ERCOT System operations may be considered as appropriate in the determination of benefits. In order for such an alternate indicator to be considered, the costs must be reasonably expected to be on-going and be adequately quantifiable and unavoidable given the physical limitation of the transmission system. These alternate indicators include:

(a) Reliability Unit Commitment (RUC) Settlement for unit operations;

(b) Visible ERCOT market indicators such as clearing prices of Congestion Revenue Rights (CRRs); and

(c) Actual Locational Marginal Prices (LMPs) and observed congestion.

3.11.3 Regional Planning Group

(1) ERCOT shall lead and facilitate a Regional Planning Group (RPG) to consider and review proposed projects to address transmission constraints and other ERCOT System needs. The RPG will be a non-voting, consensus-based organization focused on identifying needs, identifying potential solutions, communicating varying viewpoints and reviewing analyses related to the ERCOT Transmission Grid in the planning horizon. Participation in the RPG is required of all TSPs and is open to all Market Participants, consumers, other stakeholders, and PUCT Staff.

3.11.4 Regional Planning Group Project Review Process

3.11.4.1 Project Submission

(1) Any stakeholder may initiate an RPG Project Review through the submission of a document describing the scope of the proposed transmission project to ERCOT. Projects should be submitted with sufficient lead-time to allow the RPG Project Review to be completed prior to the date on which the project must be initiated by the designated TSP.

(2) Stakeholders may submit projects for RPG Project Review within any project Tier. All transmission projects in Tiers 1, 2 and 3 shall be submitted. TSPs are not required to submit Tier 4 projects for RPG Project Review, but shall include any Tier 4 projects in the cases used for development of the Regional Transmission Plan.

(3) All system improvements that are necessary for the project to achieve the system performance improvement, or to correct the system performance deficiency, for which the project is intended should be included into a single project submission.

(4) Facility ratings updates are not considered a project and are not subject to RPG Project Review.

3.11.4.2 Project Comment Process

(1) ERCOT shall conduct a comment process which is open to the stakeholders for all proposed Tier 1, 2 and 3 projects. The proposer of the project will have a reasonable period of time, as established by ERCOT, to answer questions and respond to comments submitted during this process. The Planning Guide provides details of this process.

3.11.4.3 Categorization of Proposed Transmission Projects

(1) ERCOT classifies all proposed transmission projects into one of four categories (or Tiers). Each Tier is defined so that projects with a similar cost and impact on reliability and the ERCOT market are grouped into the same Tier. For Tier classification, the total estimated cost of the project shall be used which includes costs borne by another party.

(a) A project shall be classified as Tier 1 if the estimated capital cost is greater than or equal to $100,000,000, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(b) A project shall be classified as Tier 2 if the estimated capital cost is less than $100,000,000 and a Certificate of Convenience and Necessity (CCN) is required, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(c) A project shall be classified as Tier 3 if any of the following are true:

(i) The estimated capital cost is less than $100,000,000 and greater than or equal to $25,000,000 and a CCN is not required, unless the project is considered to be a neutral project pursuant to paragraph (f) below; or

(ii) The estimated capital cost is less than $25,000,000, a CCN is not required, and the project includes 345 kV circuit reconductor of more than one mile, additional 345/138 kV autotransformer capacity, or a new 345 kV substation, unless the project is considered to be a neutral project pursuant to paragraph (f) below.

(d) A project with an estimated capital cost greater than or equal to $25,000,000 that is proposed for the purpose of replacing aged infrastructure or storm hardening shall be processed as a Tier 3 project and shall be reclassified as a Tier 4, neutral project upon ERCOT's determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily.

(e) A project shall be classified as Tier 4 if it does not meet the requirements to be classified as Tier 1, 2, or 3 or if it is considered a neutral project pursuant to paragraph (f) below.

(f) A project shall be considered a neutral project if it consists entirely of:

(i) The addition of or upgrades to radial transmission circuits;

(ii) The addition of equipment that does not affect the transfer capability of a circuit;

(iii) Repair and replacement-in-kind projects;

(iv) Transmission Facilities needed to connect a new Generation Resource, Energy Storage Resource (ESR), or Settlement Only Generator (SOG) to a new or existing substation on the existing ERCOT Transmission Grid, including the substation;

(v) The addition of static reactive devices;

(vi) A project to serve a new Load, unless such project would create a new transmission circuit connection between two stations (other than looping an existing circuit into the new Load-serving station);

(vii) Replacement of failed equipment, even if it results in a ratings and/or impedance change; or

(viii) Equipment upgrades resulting in only ratings changes.

(2) ERCOT may use its reasonable judgment to increase the level of review of a proposed project (e.g., from Tier 3 to Tier 2) from that which would be strictly indicated by these criteria, based on stakeholder comments, ERCOT analysis or the system impacts of the project.

(a) A project with an estimated capital cost greater than or equal to $50,000,000 that requires a CCN shall be reclassified and processed as a Tier 1 project upon request by a Market Participant during the comment period per Planning Guide Section 3.1.5, Regional Planning Group Comment Process.

(3) Any project that would be built by an Entity that is exempt (e.g., a Municipally Owned Utility (MOU)) from getting a CCN for transmission projects but would require a CCN if

it were to be built by a regulated Entity will be treated as if the project would require a CCN for the purpose of defining the Tier of the project.

(4) If during the course of ERCOT's independent review of a project, the project scope changes, ERCOT may reclassify the project into the appropriate Tier.

3.11.4.4 Processing of Tier 4 Projects

(1) For any project classified in Tier 4, ERCOT will not solicit comments from RPG, conduct any independent review, or provide any endorsement for the project.

3.11.4.5 Processing of Tier 3 Projects

(1) ERCOT shall accept a Tier 3 project if no concerns, questions or objections are provided during the project comment process.

(2) If reasonable ERCOT or stakeholder concerns about a Tier 3 project cannot be resolved during the time period allotted by ERCOT, the project may be processed as a Tier 2 project, unless ERCOT assesses that reasonable progress is being made toward resolving these concerns.

3.11.4.6 Processing of Tier 2 Projects

(1) ERCOT shall conduct an independent review of a submitted Tier 2 project as follows:

 (a) ERCOT's independent review shall consist of studies and analyses necessary for ERCOT to make its assessment of whether the proposed project is needed and whether the proposed project is the preferred solution to the identified system performance deficiency that the project is intended to resolve;

 (b) ERCOT shall consider all comments received during the project comment process and factor reasonable comments into its independent review of the project;

 (c) ERCOT will attempt to complete its independent review for a project in 120 days or less. If ERCOT is unable to complete its independent review based on RPG input within 120 days, ERCOT shall notify the RPG of the expected completion time;

 (d) ERCOT may, at its discretion, discuss submitted transmission projects at meetings of the RPG in order to obtain additional input into its independent review; and

 (e) ERCOT shall prepare a written report documenting the results of its independent review and recommendation on the project and shall distribute this report to the RPG.

3.11.4.7 Processing of Tier 1 Projects

(1) ERCOT shall conduct an independent review of a submitted Tier 1 project as follows:

(a) ERCOT's independent review will consist of studies and analyses necessary for ERCOT to make its assessment of whether the proposed project is needed and whether the proposed project is the preferred solution to the identified system performance deficiency that the project is intended to resolve;

(b) ERCOT will consider all comments received during the project comment process and factor reasonable comments into its independent review of the project;

(c) ERCOT will attempt to complete its independent review for a project in 150 days or less. If ERCOT is unable to complete its independent review based on RPG input within 150 days, ERCOT shall notify the RPG of the expected completion time;

(d) ERCOT may, at its discretion, discuss submitted transmission projects at meetings of the RPG in order to obtain additional input into its independent review; and

(e) ERCOT shall prepare a written report documenting the results of its independent review and recommendation on the project and shall distribute this report to the RPG.

(2) Tier 1 projects require ERCOT Board endorsement.

3.11.4.8 Determine Designated Providers of Transmission Additions

(1) Upon completion of an independent review, ERCOT shall determine the designated TSPs for any recommended transmission additions. The designated TSP for a recommended transmission addition will be the TSP that owns the end point(s) of the recommended transmission addition. The designated TSP can agree to provide the recommended transmission addition or delegate the responsibility to another TSP. If different TSPs own the two end points of a recommended transmission addition, ERCOT will designate them as co-providers of the recommended transmission addition, and they can decide between themselves what parts of the recommended transmission addition they will each provide. If they cannot agree, ERCOT will determine their responsibility following a meeting with the parties. If a designated TSP agrees to provide a recommended transmission addition but does not diligently pursue the recommended transmission addition (during the time frame before a CCN is filed, if required) in a manner that will meet the required in-service date, then upon concurrence of the ERCOT Board, ERCOT will solicit interest from TSPs through the RPG and will designate an alternate TSP.

3.11.4.9 Regional Planning Group Acceptance and ERCOT Endorsement

(1) For Tier 3 projects, successful resolution of all comments received from ERCOT and stakeholders during the project comment process will result in RPG acceptance of the proposed project. An RPG acceptance letter shall be sent to the TSP(s) for the project, the project submitter (if different from the TSP(s)), and posted on the MIS Secure Area. For Tier 2 projects, ERCOT's recommendation as a result of its independent review of the proposed project will constitute ERCOT endorsement of the need for a project except as noted in paragraph (4) below. For Tier 1 projects, ERCOT's endorsement is obtained upon affirmative vote of the ERCOT Board except as noted in paragraph (4) below. An ERCOT endorsement letter shall be sent to the TSP(s) for the project, the project submitter (if different from the TSP(s)), and the PUCT, and posted on the MIS Secure Area upon receipt of ERCOT's endorsement for Tier 1 and Tier 2 projects except as noted in paragraph (4) below.

(2) Following the completion of its independent review, ERCOT shall present all Tier 1 projects for which it finds a need to the ERCOT Board and shall provide a report to the ERCOT Board explaining the basis for its determination of need. Prior to presenting the project to the ERCOT Board, ERCOT shall present the project to the Technical Advisory Committee (TAC) for review and comment. Comments from TAC shall be included in the presentation to the ERCOT Board. ERCOT will make a reasonable effort to make these presentations to TAC and the ERCOT Board at the next regularly scheduled meetings following completion of its independent review of the project.

(3) If the asserted need for a Tier 1 or Tier 2 project is based on a service request from a specific customer, a TSP may submit the project for RPG Project Review prior to that customer signing a letter agreement for the financial security of the necessary upgrades. However, ERCOT shall not issue an independent review recommending such a project until the customer signs any required letter agreement, provides any required notice to proceed, and provides the full amount of any financial security required for the upgrades needed to serve that customer.

(4) If a TSP asserts a need for a proposed Tier 1 or Tier 2 project based in part or in whole on its own planning criteria, then ERCOT's independent review shall also consider whether a reliability need exists under the TSP's criteria. If ERCOT identifies a reliability need under the TSP's criteria, then ERCOT shall recommend a project that would address that need as well as any reliability need identified under NERC or ERCOT criteria, but shall explicitly state in the independent review report that ERCOT has assumed the TSP's criteria are valid and that an assessment of the validity of the TSP's criteria is beyond the scope of ERCOT's responsibility. ERCOT or the ERCOT Board may provide a qualified endorsement of such a project if ERCOT determines that it is justified in part under ERCOT or NERC criteria, as described in paragraph (1) above. However, neither ERCOT nor the ERCOT Board shall endorse a project that is determined to be needed solely to meet a TSP's criteria.

3.11.4.10 Modifications to ERCOT Endorsed Projects

(1) If the TSP for an ERCOT-endorsed project determines a need to make a significant change to the facilities included in the project (such as the line endpoint(s), number of circuits, voltage level, decrease in rating or similar major aspect of the project), the TSP shall notify ERCOT of the details of that change prior to filing a CCN application, if required, or prior to beginning the final design of the project if no CCN application is required. If ERCOT concurs that the proposed change is significant, the change shall be processed as a Tier 3 project, unless ERCOT determines the project should more appropriately be processed in another Tier.

(2) For economic-driven projects, if a TSP determines that the estimated project cost has increased by more than 10% over the cost described in ERCOT's endorsement, the TSP shall notify RPG prior to filing a CCN application if required, or prior to beginning the final design of the project if no CCN application is required, and provide an explanation for the cost increase. For comparison purposes, the cost of the route that best meets PUCT criteria will be used.

3.11.4.11 Customer or Resource Entity Funded Transmission Projects

(1) If an affected TSP elects to pursue a Customer or Resource Entity funded transmission project that would have been classified as a Tier 1, Tier 2, or Tier 3 project for RPG Project Review, the TSP(s) shall conduct a reliability impact assessment of the proposed transmission project and shall submit a report summarizing the results of the reliability impact assessment for RPG Project Review. Such projects shall be processed according to their Tier classification and shall be reclassified as a Tier 4, neutral project upon ERCOT's determination that any concerns, questions or objections raised during the comment process have been resolved satisfactorily.

(2) ERCOT's independent review of a Tier 1 or Tier 2 Customer or Resource Entity funded transmission project will be limited to assessing the reliability and congestion impact of the proposed project and submitting a report summarizing the results and findings to RPG for review and discussion. ERCOT will not endorse the project and will not present the project to the ERCOT Board. However, ERCOT may recommend the project not be implemented or recommend changes to the project scope if, in ERCOT's sole discretion, the project negatively impacts the reliability or congestion of the ERCOT System.

(3) Customer or Resource Entity funded Tier 4 projects do not need to go through this review process.

3.11.5 Transmission Service Provider and Distribution Service Provider Access to Interval Data

(1) ERCOT shall provide specific interval data for Load and generation to TSPs and/or Distribution Service Providers (DSPs), upon request, in accordance with confidentiality as defined in Section 1.3, Confidentiality.

(a) The TSP's and/or DSP's request for interval data shall identify the reason for requesting the information in regards to impact to the planning process (e.g. build power flow cases, conduct a specific study, etc.).

(b) ERCOT shall evaluate the TSP and/or DSP request and validate reasons provided.

(c) Upon ERCOT validation of the TSP and/or DSP request, the data provided shall include meter data measured at points of injection and points of delivery which will measurably impact the TSP's and/or DSP's planning and operations as determined by ERCOT (e.g., determination of the TSP's and/or DSP's system Load or power flows).

(d) If ERCOT determines that the request is invalid and denies it, ERCOT shall provide the reasoning for denying the request.

3.11.6 Generation Interconnection Process

(1) The generation interconnection process facilitates the interconnection of new generation units in the ERCOT Region by assessing the transmission upgrades necessary for new generating units to operate reliably. The process to study interconnecting new generation or modifying an existing generation interconnection to the ERCOT Transmission Grid is covered in the Planning Guide. The generation interconnection study process primarily addresses the direct connection of generation Facilities to the ERCOT Transmission Grid and directly-related projects. Projects that are identified through this process and are regional in nature may be reviewed through the RPG Project Review process upon recommendation by the TSP or ERCOT, subject to the confidentiality provisions in Section 1.3, Confidentiality.

(2) ERCOT shall perform an independent economic analysis of the Transmission Facilities needed to connect a new Generation Resource, ESR, or SOG to a new or existing substation on the existing ERCOT Transmission Grid, including the substation, that are identified through this process that are expected to cost more than $25,000,000. This economic analysis is performed only for informational purposes; as such, no ERCOT endorsement will be provided. The results of the economic analysis shall be included in the interconnection study posting.

(3) Additional upgrades to the ERCOT Transmission Grid that might be cost-effective as a result of new or modified generation may be initiated by any stakeholder through the RPG Project Review procedure described in Section 3.11.4, Regional Planning Group Project Review Process, at the appropriate time, subject to the confidentiality provisions of the generation interconnection procedure.

3.12 Load Forecasting

(1) ERCOT shall produce and use Load forecasts to serve operations and planning objectives.

(a) ERCOT shall update and post hourly on the ERCOT website, a "Seven-Day Load Forecast" as described in Section 3.12.1, Seven-Day Load Forecast, that provides forecasted hourly Load over the next 168 hours for each of the Weather Zones and for each of the Forecast Zones.

(b) ERCOT shall develop and post monthly on the Market Information System (MIS) Secure Area a "36-Month Load Forecast" that provides a daily minimum and maximum Load forecast for the next 36-months for the ERCOT Region, for each of the Weather Zones, and for each of the Forecast Zones. The 36-Month Load Forecast is used in the Outage coordination process and for Resource adequacy reporting.

[NPRR1004: Insert paragraph (c) below upon system implementation:]

(c) ERCOT shall generate and post daily on the ERCOT website Load distribution factors that provide hourly distribution for non-Private Use Network Loads by means of the Mid-Term Load Forecast (MTLF). Private Use Network Loads will be generated separately. If ERCOT decides, in its sole discretion, to change the Load distribution factors for reasons such as anticipated weather events or holidays, ERCOT shall select representative conditions as an input reasonably reflecting the anticipated Load in the Operating Day. ERCOT may also modify the Load distribution factors to account for predicted differences in network topology between the Load forecast and Operating Day. ERCOT may set auto error correction settings and apply Load forecast validation to better represent Load Profiles. Private Use Network Load distribution factor data is redacted from the MIS postings and all self-serve Load's distribution factors are set to zero when the data is used by the downstream applications.

(2) ERCOT shall produce and post to the ERCOT website an Intra-Hour Load Forecast (IHLF) that provides a rolling two hour five minute forecast of ERCOT-wide Load.

3.12.1 Seven-Day Load Forecast

(1) ERCOT shall use the Seven-Day Load Forecast to predict hourly Loads for the next 168 hours based on current weather forecast parameters within each Weather Zone. Preparation for Day-Ahead Operations requires an accurate forecast of the Loads for which generation capacity must be secured. The Seven-Day Load Forecast must have a "self-training" mode that allows ERCOT to review historic Load data and provide the ability to retrain the Seven-Day Load Forecast algorithm.

[NPRR975: Insert paragraphs (a) and (b) below upon system implementation:]

(a) ERCOT will use a variety of Load forecast models and will select the Load forecast model that best fits the expected conditions for each hour of the next

168 hours as the Seven-Day Load Forecast for that hour and may update this selection as expected conditions change.

(b) If the selected forecast used at the time of the Day-Ahead Reliability Unit Commitment (DRUC) for the peak Demand hour of any of the next seven days is above or below the average of the forecast models for that hour by the greater of 2000 MW or 4% of the average of the forecast models for that hour, ERCOT shall produce and post to the ERCOT website an explanation of why the outlier Load forecast model was selected for that hour.

(2) The inputs for the Seven-Day Load Forecast are as follows:

(a) Hourly forecasted weather parameters for the weather stations within the Weather Zones, which are updated at least once per hour; and

(b) Training information based on historic hourly integrated Weather Zone Loads.

(3) ERCOT shall review the forecast suggested by Seven-Day Load Forecast and shall use its judgment, if necessary, to modify the result prior to implementation in the Ancillary Service Capacity Monitor, Day-Ahead Reliability Unit Commitment (DRUC), Hour-Ahead Reliability Unit Commitment (HRUC), and Resource adequacy reporting.

3.12.2 Study Areas

(1) ERCOT shall develop and use Study Areas for Load forecasting and study purposes, and will provide the Load forecast data to the market. A list of Study Areas shall be available on the ERCOT website.

3.12.3 Seven-Day Study Area Load Forecast

(1) ERCOT shall develop and post hourly on the ERCOT website a "Seven-Day Study Area Load Forecast" to predict the hourly Loads for the next 168 hours based on current weather forecast parameters within each Study Area.

(a) The forecast referenced in paragraph (1) above will not affect the values within the "Seven-Day Load Forecast" by Weather Zone and/or Forecast Zone.

3.13 Renewable Production Potential Forecasts

(1) ERCOT shall produce forecasts of Renewable Production Potential (RPP) for Wind-powered Generation Resources (WGRs) and PhotoVoltaic Generation Resources (PVGRs) to be used as an input into the Day-Ahead Reliability Unit Commitment (DRUC) and Hour-Ahead Reliability Unit Commitment (HRUC). ERCOT shall produce the forecasts using information provided by WGR/PVGR Entities, meteorological

information, and Supervisory Control and Data Acquisition (SCADA). WGR and PVGR Entities shall install telemetry at their respective Resources and transmit the ERCOT-specified site-specific meteorological information to ERCOT. WGR and PVGR Entities shall also provide detailed equipment status at the WGR/PVGR facility as specified by ERCOT to support the RPP forecast. ERCOT shall post forecasts for each WGR and PVGR to the Qualified Scheduling Entities (QSEs) representing WGRs and/or PVGRs on the Market Information System (MIS) Certified Area. QSEs shall use the ERCOT-provided forecasts for WGRs/PVGRs throughout the Day-Ahead and Operating Day for applicable markets and Reliability Unit Commitments (RUCs). Similar requirements for run-of-the-river hydro must be developed as needed.

[NPRR1029: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall produce forecasts of Renewable Production Potential (RPP) for Wind-powered Generation Resources (WGRs), PhotoVoltaic Generation Resources (PVGRs), and the intermittent renewable generation component of each DC-Coupled Resource to be used as an input into the Day-Ahead Reliability Unit Commitment (DRUC) and Hour-Ahead Reliability Unit Commitment (HRUC). ERCOT shall produce the forecasts using information provided by WGRs, PVGRs, and DC-Coupled Resources; meteorological information; and Supervisory Control and Data Acquisition (SCADA). A Resource Entity with a WGR, PVGR, or DC-Coupled Resource shall install equipment to enable telemetry of site-specific meteorological information that ERCOT determines is necessary to produce the RPP forecast, and the Resource Entity's QSE shall telemeter such information and Resource status information to ERCOT. ERCOT shall post forecasts for each WGR and PVGR and for the intermittent renewable generation component of each DC-Coupled Resource to the MIS Certified Area for the Qualified Scheduling Entity (QSE) representing that WGR, PVGR, or DC-Coupled Resource. QSEs shall use the ERCOT-provided forecasts for WGRs, PVGRs, and DC-Coupled Resources in the Day-Ahead and throughout the Operating Day for applicable markets and Reliability Unit Commitments (RUCs). Similar requirements for run-of-the-river hydro must be developed as needed.

(2) ERCOT shall develop cost-effective tools or services to forecast energy production from Intermittent Renewable Resources (IRRs) with technical assistance from QSEs scheduling IRRs. ERCOT shall use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. ERCOT shall post on the MIS Secure Area objective criteria and thresholds for unbiased, accurate forecasts within five Business Days of change.

[NPRR1029: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall develop cost-effective tools or services to forecast energy production from Intermittent Renewable Resources (IRRs) and from the intermittent renewable

generation component of each DC-Coupled Resource with technical assistance from QSEs representing such Resources. ERCOT shall use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. ERCOT shall post on the MIS Secure Area objective criteria and thresholds for unbiased, accurate forecasts within five Business Days of change.

3.14 Contracts for Reliability Resources and Emergency Response Service Resources

(1) ERCOT shall procure Reliability Must-Run (RMR) Service, Black Start Service (BSS) or Emergency Response Service (ERS) through Agreements.

[NPRR885: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall procure Reliability Must-Run (RMR) Service, Must-Run Alternative (MRA) Service, Black Start Service (BSS), or Emergency Response Service (ERS) through Agreements.

3.14.1 Reliability Must Run

(1) RMR Service is the use by ERCOT, under contracts with Resource Entities, of capacity and energy from Generation Resources that otherwise would not operate and that are necessary to provide voltage support, stability or management of localized transmission constraints under applicable reliability criteria, where market solutions do not exist.

(a) Upon receiving a Notification of Suspension of Operations (NSO) from a Resource Entity as described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT may begin procurement of RMR Service under this Section.

(b) Before entering into an RMR Agreement, ERCOT shall assess alternatives to the proposed RMR Agreement. ERCOT shall evaluate and present in a written report posted on the Market Information System (MIS) Secure Area the information in items (i) through (iv) below. ERCOT is not limited in the number of additional scenarios it chooses to evaluate. The written report shall include an explanation as to why the items below are insufficient, either alone or in combination, to fill the requirement that will be met by the potential RMR Unit. The report shall be posted in the time frame required under paragraph (5) of Section 3.14.1.2, ERCOT Evaluation Process. The list of alternatives ERCOT must consider includes (as reasonable for each type of reliability concern identified):

(i) Re-dispatch/reconfiguration through operator instruction;

(ii) Automatic Mitigation Plans (AMPs) and Remedial Action Plans (RAPs);

(iii) Remedial Action Schemes (RASs) initiated on unit trips or Transmission Facilities' Outages; and

(iv) Any other operational alternatives deemed viable by ERCOT.

(c) ERCOT shall minimize the use of RMR Units as much as practicable subject to the other provisions of these Protocols. ERCOT may Dispatch an RMR Unit at any time for ERCOT System security.

(d) Each RMR Unit must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing.

(e) ERCOT may execute RMR Agreements for no less than one month and no more than one year, with one exception. ERCOT may execute an RMR Agreement for a term longer than 12 months if the Resource Entity must make a significant capital expenditure to meet environmental regulations or to ensure availability to continue operating the RMR Unit so as to make an RMR Agreement in excess of 12 months appropriate, in ERCOT's opinion. The term of a multi-year RMR Agreement must take into account the appropriate RMR exit strategy discussed in Section 3.14.1.4, Exit Strategy from an RMR Agreement. In the event ERCOT chooses to contract for an RMR Unit for longer than one year, ERCOT shall annually re-evaluate the need for the RMR Unit under the criteria set forth in paragraph (b) above. If ERCOT determines the RMR Unit is no longer needed, ERCOT shall enter into exit negotiations with the contract signatories to attempt to exit the contract early. However, ERCOT shall not enter into such negotiations until a Market Notice is issued providing the anticipated RMR exit time frame. The RMR standard Agreement is included in Section 22, Attachment B, Standard Form Reliability Must-Run Agreement. ERCOT shall post each RMR Agreement in its entirety, including amendments or modifications thereto, within five Business Days of execution on the MIS Secure Area.

(f) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability according to the Operating Guides. A combined-cycle generation Facility must be treated as a single unit for RMR purposes unless the combustion turbine and the steam turbine can operate separately. If the steam turbine and combustion turbine can operate separately, and the steam turbine is powered by waste heat from more than one combustion turbine, the combustion turbine accepted for RMR Service and a proportionate part of the steam turbine must be treated as a single unit for RMR purposes. If the combustion turbine accepted for RMR Service can operate separately from the steam turbine, and only the combustion turbine is accepted as an RMR Unit, the RMR energy price will be reduced by the value of the combustion turbine's waste heat calculated at the Fuel Index Price (FIP), except when the steam turbine is Off-Line. ERCOT shall post to the MIS Secure Area the criteria upon which it evaluates whether an RMR Unit meets the test of operational necessity to support ERCOT System reliability within five Business Days of change and shall issue a Market Notice stating the determination is available. This includes the case where a unit previously identified by ERCOT as potentially needed for RMR Service is no longer needed regardless of whether an RMR Agreement was ever signed.

(g) A Resource Entity cannot be compelled to enter into an RMR Agreement. A Resource Entity that owns or controls a Generation Resource that is uneconomic to remain in service can voluntarily petition ERCOT for contracted RMR status by following the process in this subsection. ERCOT shall determine whether the Generation Resource is necessary for system reliability based on the criteria set forth in this Section.

(h) ERCOT must contract for the entire capacity of each RMR Unit.

(i) ERCOT shall post on the MIS Secure Area all information relative to the use of RMR Units including energy deployed monthly.

(j) The Resource Entity that owns or controls the RMR Unit may not use the RMR Unit for:

    (i) Participating in the bilateral energy market;

    (ii) Self-providing of energy except for plant auxiliary Load obligations under the RMR Agreement; and

    (iii) Providing of Ancillary Service to any Entity.

(k) ERCOT shall issue a Market Notice on the need for an RMR Unit prior to entering negotiations for the RMR Unit. Such Market Notice shall include the link to the ERCOT final RMR evaluation, the Resource name and unit code, the name of the Resource Entity, the name of the Qualified Scheduling Entity (QSE) for the Resource, the Resource MW rating by Season, and potential duration of the RMR Agreement, including anticipated start and end dates.

(l) ERCOT shall, through the issuance of Market Notices, provide the same information, contemporaneously, about the need for, or elimination of an RMR Unit to all registered Market Participants, including QSEs and Resource Entities with RMR Units.

3.14.1.1 Notification of Suspension of Operations

(1) Except for the occurrence of a Forced Outage, a Resource Entity must notify ERCOT in writing no less than 150 days prior to the date on which the Resource Entity intends to cease or suspend operation of a Generation Resource for a period of greater than 180 days. If a Generation Resource is to be mothballed on a seasonal basis, the Resource Entity must notify ERCOT in writing no less than 90 days prior to the suspension date and identify its Seasonal Operation Period.

(2) The Resource Entity shall submit a completed Part I and Part II of the NSO (found in Section 22, Attachment E, Notification of Suspension of Operations). The Resource Entity may also complete Part III of the NSO and submit it along with Parts I and II, or may wait to submit Part III up to ten days after ERCOT makes a determination that the proposed suspension of the Generation Resource would result in a performance deficiency for which the Generation Resource has a material impact. Part I of the NSO must include the attestation of an officer of the Resource Entity that the Generation Resource is uneconomic to remain in service as currently designated and will be unavailable for Dispatch by ERCOT for a period specified in the NSO.

(3) A Resource Entity ceasing or suspending operations as a result of a Forced Outage lasting greater than 180 days shall notify ERCOT as soon as practicable. An NSO submitted due to a Forced Outage:

(a) Will not be evaluated for RMR status; and

(b) Will not be posted on the MIS, except that information contained in the NSO may be included in reports in accordance with Section 3.2.6.2.2, Total Capacity Estimate.

(4) At least 60 days before the expiration of an existing RMR Agreement, the Resource Entity may apply to renew the RMR Agreement by submitting a new NSO (including both Part I and Part II). Upon receipt of such a renewal request, ERCOT shall update and post to the MIS Secure Area studies as set forth in Section 3.14.1, Reliability Must Run, within 15 Business Days.

3.14.1.2 ERCOT Evaluation Process

(1) Upon receipt of an NSO under Section 3.14.1.1, Notification of Suspension of Operations, ERCOT shall post the NSO on the MIS Secure Area and shall post all existing relevant studies and data and provide a Market Notice of the NSO and posting of the studies and data.

(2) Within 21 days after receiving the NSO described in paragraph (1) above, unless otherwise notified by ERCOT that a shorter comment period is required, Market Participants may submit comments to ERCOT on whether the Generation Resource(s) referenced in the NSO is necessary to support ERCOT System reliability or should qualify for a multi-year RMR Agreement. ERCOT shall consider and post all submitted comments on the MIS Secure Area.

(3) ERCOT shall conduct a reliability analysis of the need for the Generation Resource(s) to support ERCOT System reliability.

(a) ERCOT shall use a Load forecast consistent with current Regional Transmission Plan assumptions and methodologies for the appropriate season(s). If additional new Generation Resources meet the criteria in Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall include those additional Generation Resources with the appropriate seasonal ratings.

(b) If the NSO indicates that the Generation Resource(s) will decommission or suspend operation, ERCOT, in its sole discretion, may perform transmission reliability analysis over a planning horizon as defined by the available base cases but not to exceed two years.

(c) For purposes of the reliability analysis, ERCOT shall use the following criteria to identify a performance deficiency that is materially impacted by the Generation Resource:

(i) Without the Generation Resource, there are one or more Transmission Facilities loaded above their Normal Rating under pre-contingency conditions.

(ii) Without the Generation Resource, there is any instability or cascading for any of the following conditions:

(A) Pre-contingency;

(B) Normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or flexible alternating current transmission system (FACTS) device;

(C) Unavailability of a generating unit, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device; or

(D) Unavailability of a 345/138 kV transformer, followed by Manual System Adjustments, followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iii) Without the Generation Resource, there are one or more Transmission Facilities loaded above 110% of the Emergency Rating under normal system conditions followed by the contingency loss of a generating unit, transmission circuit, common tower outage, transformer, shunt device, or FACTS device.

(iv) For paragraphs (i) through (iii) above, the Generation Resource will only be deemed to have a material impact on a performance deficiency that is caused by a thermal overload(s) if the Generation Resource has a more than 2% unloading Shift Factor on the Transmission Facility(s) that is overloaded and more than 5% unloading impact on the Transmission Facility(s) that is overloaded. For purposes herein, an unloading impact is a measure of a reduction in flow on a Transmission Facility as a percent of its Rating due to a unit injection of power from the Generation Resource.

(v) ERCOT may, in its sole discretion, deviate from the above criteria in order to maintain ERCOT System reliability. However, ERCOT shall present its reasons for deviating from the above criteria to the Technical Advisory Committee (TAC) and ERCOT Board.

(d) ERCOT, in consultation with affected Transmission Service Provider(s) (TSP(s)), may rely upon the results of past planning studies to determine if the Generation Resource is necessary to support ERCOT System reliability. The past planning studies must have used the same or more restrictive reliability criteria than the criteria described in paragraph (c) above.

(e) Additionally, ERCOT shall conduct any other analysis (e.g., operations studies) as required and shall post all study data and results and all analyses and its determination on the MIS Secure Area and issue a Market Notice of its determination.

(4) Within 30 days after receiving the NSO, ERCOT shall issue a Market Notice indicating the status of the reliability analysis referenced in paragraph (3) above. The Market Notice will indicate one of the following:

(a) ERCOT has completed its reliability analysis and the Generation Resource is not required to support ERCOT System reliability;

(b) ERCOT has completed its reliability analysis and the analysis identifies a performance deficiency for which the Generation Resource has a material impact; or

(c) ERCOT has not completed its reliability analysis and will need additional time to complete the assessment.

(5) Within 60 days after receiving Part I and Part II of the NSO, ERCOT shall complete its reliability analysis described in paragraph (3) above and shall issue a Market Notice describing the results of its reliability analysis. If ERCOT determines that the Generation Resource is not needed to support ERCOT System reliability, then the Generation Resource may cease or suspend operations according to the schedule in its NSO, unless ERCOT in its sole discretion permits the Generation Resource to suspend operations at an earlier date, and ERCOT shall note this in the Market Notice.

(6) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, ERCOT shall issue a Request for Proposal (RFP) for Must-Run Alternatives (MRAs). ERCOT shall include in the RFP reasonably available information that would enable potential MRAs to assess the feasibility of submitting a proposal to provide a more cost-effective alternative to the Generation Resource, including any known minimum technical requirements and/or

operational characteristics required to eliminate the identified performance deficiency. The MRA RFP shall specify the expected number of hours that an MRA would be needed during the contract period, and the hours of the day, by season, that the MRA would be required to be available. ERCOT shall establish an RFP response schedule such that responses can be evaluated prior to 150 days after submittal of the NSO.

(7) Within ten days after a determination by ERCOT that the proposed suspension of the Generation Resource would result in a performance deficiency on which the Generation Resource has a material impact, as described in this Section, the Resource Entity shall, if it has not already done so, complete and submit to ERCOT Part III of the NSO (Section 22, Attachment E, Notification of Suspension of Operations). ERCOT shall post the Part III information on the MIS Secure Area. Concurrently, the Generation Resource shall submit an initial estimated budget used in the calculation of the proposed Standby Cost and RMR fuel adder, prepared in accordance with Section 3.14.1.11, Budgeting Eligible Costs, and Section 3.14.1.20, Budgeting Fuel Costs, to ERCOT. On or before the 11th day after the determination or the receipt of Part III of the NSO, whichever comes first, ERCOT and the Resource Entity shall begin good faith negotiations on an RMR Agreement. These negotiations shall include the budgeting process for Eligible Costs and for fuel costs as detailed in Section 3.14.1.11 and Section 3.14.1.20.

(8) ERCOT shall issue a Market Notice on the status of the RMR Unit or MRA, including the start date, duration of the RMR or MRA Agreement, the Standby Cost ($/Hour) as applicable, and the amount of MW under contract, within 24 hours of signing an RMR or MRA Agreement with a Resource Entity.

(9) Except in cases where the Generation Resource is to be mothballed on a seasonal basis, if, after 150 days following ERCOT's receipt of Part I and Part II of the NSO, ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR or MRA Agreement, then the Resource Entity may file a complaint with the Public Utility Commission of Texas (PUCT) under subsection (e)(1) of P.U.C. SUBST. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas. If the Generation Resource is to be mothballed on a seasonal basis, then the Resource Entity may file such a complaint with the PUCT under subsection (e)(1) of P.U.C. SUBST. R. 25.502 if ERCOT has neither notified the Resource Entity that the continued operation of the Generation Resource is not required nor obtained ERCOT Board approval to enter into an RMR Agreement within 90 days following ERCOT's receipt of Part I and Part II of the NSO.

(10) If the ERCOT Board approves entering into an RMR Agreement but ERCOT and the Resource Entity have not both executed the RMR Agreement by the date on which the Resource Entity intends to cease or suspend operation of the Generation Resource, then the Resource Entity shall maintain that Generation Resource(s) so that it is available for Reliability Unit Commitment (RUC) commitment until no longer required to do so under subsection (e)(2) of P.U.C. SUBST. R. 25.502.

3.14.1.2.1 ERCOT Evaluation of Seasonal Mothball Status

(1) ERCOT shall evaluate requests to place Generation Resources on a seasonal mothball status pursuant to the guidelines provided in Section 3.14.1.2, ERCOT Evaluation Process, except as stated below.

(2) Within 30 days after receiving the NSO described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT shall issue a Market Notice indicating the status of the reliability analysis described in paragraph (3) of Section 3.14.1.2. The Market Notice will indicate one of the following:

(a) ERCOT has completed its reliability analysis and the Generation Resource is not required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable;

(b) ERCOT has completed its reliability analysis and the analysis identifies a performance deficiency for which the Generation Resource has a material impact during the portion of the year when the Generation Resource would be unavailable; or

(c) ERCOT has not completed its reliability analysis and will need additional time to complete the assessment.

(3) Within 60 days after receiving the NSO ERCOT shall complete its reliability analysis described in paragraph (3) of Section 3.14.1.2 and, if it has not already done so, ERCOT shall issue a Market Notice stating whether the Generation Resource is required to support ERCOT System reliability during the portion of the year when the Generation Resource would be unavailable.

3.14.1.3 ERCOT Board Approval of RMR and MRA Agreements

(1) If ERCOT determines that an RMR or MRA Agreement is a cost-effective solution to remedy a performance deficiency for which the suspending Generation Resource has a material impact as described in paragraph (3) of Section 3.14.1.2, ERCOT Evaluation Process, or if ERCOT has identified such a performance deficiency but has determined that entering into an RMR or MRA Agreement is not a cost-effective solution to that performance deficiency, then ERCOT shall present this finding to the ERCOT Board for approval. In seeking such approval, ERCOT shall stipulate to the ERCOT Board that:

(a) The Resource Entity provided a complete and timely NSO including a sworn attestation supporting its claim of pending Generation Resource closure;

(b) ERCOT received all of the data necessary to evaluate the need for and provisions of the RMR or MRA Agreement, and that information was posted on the MIS Secure Area by ERCOT as it became available to ERCOT;

(c) When executed, the signed RMR or MRA Agreement will comply with the ERCOT Protocols and be posted on the MIS Secure Area;

(d) ERCOT evaluated:

(i) The reasonable alternatives to a specific RMR Agreement as set forth in Section 3.14.1, Reliability Must Run, and compared the alternatives against the feasibility, cost and reliability impacts of the signed RMR Agreement;

(ii) The timeframe in which ERCOT expects each unit to be needed for reliability; and

(iii) The specific type and scope of reliability concerns identified for each RMR Unit or MRA as applicable.

(2) ERCOT shall execute the RMR or MRA Agreement as soon as feasible after receiving ERCOT Board approval to do so.

(3) ERCOT shall post on the MIS Secure Area, as they become available, unit-specific studies, reports, and data, by which ERCOT justified entering into the RMR or MRA Agreement.

3.14.1.4 Exit Strategy from an RMR Agreement

(1) No later than 90 days after the execution of an RMR Agreement, ERCOT shall report to the Board and post on the MIS Secure Area a list of feasible alternatives that may, at a future time, be more cost-effective than the continued renewal of the existing RMR Agreement. Through the ERCOT System planning process, ERCOT shall develop a list of potential alternatives to the service provided by the RMR Unit. At a minimum, the list of potential alternatives that ERCOT must consider include, building new or expanding existing Transmission Facilities, installing voltage control devices, soliciting or buying by auction interruptible Load from Retail Electric Providers (REPs), or extending the existing RMR Agreement on an annual basis. If a cost-effective alternative to the service provided by the RMR Unit is identified, ERCOT shall provide a proposed timeline to study and/or implement the alternative.

3.14.1.5 Evaluation of Alternatives

(1) In evaluating responses to the RFP for MRAs, ERCOT shall not consider any response that, in ERCOT's sole opinion, does not facially demonstrate that the proposed MRA meets the eligibility requirements specified in Section 3.14.4.1, Overview and Description of MRAs, and the availability criteria and other conditions specified in the RFP for MRAs.

(2) ERCOT shall consider any of the following options to resolve an identified performance deficiency:

(a) The Generation Resource proposed for a suspension of operations;

(b) All acceptable MRA proposals; and

(c) Any transmission upgrades that can be implemented prior to the time period for which the performance deficiency has been identified.

(3) ERCOT staff shall select the option or combination of options, if any, that most cost-effectively address the performance deficiency, as long as the cost of the selected options is justified given the possible impact to Customers due to the performance deficiency. If ERCOT determines that no option cost-effectively resolves the performance deficiency, then ERCOT shall not select any option. In selecting the most cost-effective option, ERCOT will consider the following factors:

(a) The degree to which the option addresses the identified performance deficiency;

(b) The total expected cost of each option;

(c) Expected unit performance of the Generation Resource proposed for suspension of operations, including start-up time, minimum run-time, minimum down-time, and historical unit outage data;

(d) Operational limitations of proposed MRAs, including start-up times, minimum run-times, ramp periods, and return-to-service times;

(e) Other operational constraints or operational benefits of the proposed option; and

(f) Any other factors which ERCOT determines are relevant to the evaluation, and for which ERCOT can develop quantifiable criteria with which to evaluate all proposed options.

(4) In evaluating the expected impact to Customers due to the performance deficiency, ERCOT shall consider the following factors:

(a) Expected amount of Customer Demand affected (MWh);

(b) Expected number of hours during which Customers will be affected;

(c) Number of Customers affected;

(d) Possible additional Customer impacts due to unforeseen conditions, such as Generation Resource unavailability, transmission circuit Outages, or Load variation due to extreme weather; and

(e) Potential economic impact to Customers.

(5) ERCOT staff shall recommend the selected option or options to the ERCOT Board of Directors for approval, or shall recommend that the ERCOT Board of Directors decline to accept any option, if no eligible, cost-effective option has been identified. ERCOT staff shall provide sufficient information to justify its recommendation. The ERCOT Board of Directors may approve or reject the proposed recommendation, or may direct ERCOT staff to pursue an agreement to procure one or more options not proposed by ERCOT staff.

3.14.1.6 Transmission System Upgrades Associated with an RMR and/or MRA Exit Strategy

(1) This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) ERCOT and the TSP(s) responsible for constructing any upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall coordinate construction clearances necessary to allow timely completion of all planned Transmission Facilities upgrades.

(b) The TSP(s) responsible for constructing upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall establish and send to ERCOT estimated Outage information, including completion dates and associated model information to ERCOT per Section 3.1.4, Communications Regarding Resource and Transmission Facilities Outages. For purposes of this Section, a Transmission Facility upgrade will be considered initiated upon the TSP authorizing any expenditures on the upgrade including, but not limited to, material procurement, right-of-way acquisition, and regulatory approvals.

(c) Upon initiation of the project, the TSP(s) responsible for constructing upgrades relating to the Transmission Facilities that are part of an RMR or MRA exit strategy shall provide to ERCOT monthly updates of the project's status, noting any acceleration or delay in planned completion date. ERCOT shall report this data through the MIS as described in Section 12.2, ERCOT Responsibilities. Within 60 days of the completion date shown in the Notice provided per Section 3.1.4, for the Transmission Facilities upgrades, the TSP shall coordinate more timely updates if the timeline changes significantly.

(d) Within ten Business Days after completion of the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy, ERCOT shall publish a Market Notice of such completion and the effective date of termination of the associated RMR or MRA Agreement.

3.14.1.7 RMR or MRA Contract Termination

(1) This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(2) Once a suitable RMR or MRA exit strategy has been developed as defined in Section 3.14.1.4, Exit Strategy from an RMR Agreement, and the strategy has been approved by the ERCOT Board and the affected TSP(s), the TSP(s) responsible for the Transmission Facilities upgrades, when requested by ERCOT, shall submit to ERCOT:

(a) A preliminary construction outage schedule necessary to complete the Transmission Facilities upgrades. Submissions, changes, approvals, rejections, and withdrawals regarding the preliminary construction outage schedule shall be processed through the ERCOT Outage Scheduler on the ERCOT MIS. Such construction outage schedule shall be updated monthly; or

(b) A Certificate of Convenience and Necessity (CCN) application timeline for projects requiring such PUCT certification. Once a CCN has been granted by the PUCT, the TSP(s) shall be required to meet the requirements in item (a) above.

(3) ERCOT shall review and approve or reject each construction outage schedule as provided in accordance with procedures developed by ERCOT in compliance with Section 3.1, Outage Coordination.

(4) The TSP(s) responsible for the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy shall provide to ERCOT a project status and an estimated project completion date within five Business Days of ERCOT's request.

(5) If ERCOT determines that a mutually agreeable preliminary construction outage schedule can be accommodated during the fall, winter, or spring, ERCOT and the TSP shall collaborate to determine if the 90 day termination notice for the RMR and/or MRA can be issued as soon after the summer load Season of the preceding year as possible and publish a Market Notice of these terminations. ERCOT and the TSP may give consideration to the risk of the decision to terminate the RMR and/or MRA Agreement and any options, such as RAPs and/or Mitigation Plans that could be used to mitigate transmission construction delays.

3.14.1.8 RMR and/or MRA Contract Extension

(1) This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) Forty-five days prior to the termination date of an existing RMR or MRA Agreement, pursuant to the 90-day termination notice as described in paragraph A(2) of Section 3, Term and Termination, of Section 22, Attachment B, Standard Form Reliability Must-Run Agreement, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) or other exit strategies necessary to allow termination of an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that a delay in the termination date of the existing RMR or MRA Agreement is necessary to allow completion of the Transmission Facilities upgrade(s), it shall provide written Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned termination date. Within 24 hours of ERCOT providing this Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA, ERCOT shall issue a Market Notice on its intent to execute an extension to the existing RMR or MRA Agreement. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board's next regularly scheduled meeting.

(b) Forty-five days prior to the expiration date of an existing RMR or MRA Agreement for which the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA has applied for renewal, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) necessary to eliminate the reliability need for a Resource with an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that an extension of the existing RMR or MRA Agreement of no more than 90 days would allow completion of the Transmission Facilities upgrade(s), it shall provide written Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned expiration date. Within 24 hours of ERCOT providing this Notice to the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA, ERCOT shall issue a Market Notice on its intent to execute an extension to the existing RMR or MRA Agreement. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board's next regularly scheduled meeting.

(c) ERCOT may extend the existing RMR or MRA Agreement as necessary to allow completion of the Transmission Facilities upgrade(s), but in no event shall the extension last more than 90 days from the termination or expiration date of the existing RMR or MRA Agreement.

(d) Forty-five days prior to the end of the period for which the existing RMR or MRA Agreement has been extended, ERCOT shall assess whether the transmission upgrades are likely to be completed. If ERCOT determines that the upgrades are not likely to be completed, ERCOT shall enter into negotiations with the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA to negotiate a new RMR or MRA Agreement to allow completion of the planned transmission upgrades. ERCOT shall issue a Market Notice on or before the date that extension negotiations begin with the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA. The Market Notice must contain the name and seasonal MW ratings of the RMR Unit or MRA and the expected duration of the contract extension, including the expected termination date. Additionally, the Market Notice must contain a description of the exit strategy and the status of progress of exit strategy projects. ERCOT shall notify the ERCOT Board of the extension at the ERCOT Board's next regularly scheduled meeting.

3.14.1.9 Generation Resource Status Updates

(1) By April 1st and October 1st of each year and when material changes occur, every Resource Entity that owns or controls a Mothballed Generation Resource or an RMR Unit shall report to ERCOT, on a unit-specific basis, the estimated lead time required for each Resource to be capable of returning to service and, in percentage terms, report probable generation capacity from each Resource that the Resource Entity expects to return to service in each Season of each of the next ten years.

(2) For modeling purposes, ERCOT and TSPs shall rely on the most recent submittal of the following two Notifications with respect to an RMR Unit, Mothballed Generation Resource or Decommissioned Generation Resource: Section 22, Attachment E, Notification of Suspension of Operations, or Section 22, Attachment H, Notification of Change of Generation Resource Designation. Except in the case of an NSO submitted due to a Forced Outage, ERCOT shall post each submitted NSO and Notification of Change of Generation Resource Designation to the MIS Secure Area and issue a Market Notice notifying Market Participants of the posting as soon as practicable, but no later than five Business Days after receipt.

(3) A Mothballed Generation Resource that is not mothballed indefinitely shall remain modeled in all ERCOT systems at all times, (i.e., will not be flagged as "mothballed" in ERCOT's models) and, when it is not available, the Resource Entity shall designate the Generation Resource as on Planned Outage in the Outage Scheduler.

(4) Except for Mothballed Generation Resources that operate under a Seasonal Operation Period, a Resource Entity with a Mothballed Generation Resource shall notify ERCOT in writing no less than 30 days prior to the date on which the Resource Entity intends to return a Mothballed Generation Resource to service by completing a Notification of Change of Generation Resource Designation.

(5) A Resource Entity must submit a Notification of Change of Generation Resource Designation no later than 60 days prior to the conclusion of an RMR Agreement.

(6) A Resource Entity with a Mothballed Generation Resource that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to begin its Seasonal Operation Period if the first date of operation is prior to the date designated by the Resource Entity in its NSO. A Resource Entity with a Mothballed Generation Resource that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the end date designated by the Resource Entity in its NSO if the Resource Entity intends to suspend operation later than that date. Notifications under this section shall be provided by the

Resource Entity by completing a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(7) Once the Resource Entity notifies ERCOT that a Mothballed Generation Resource is operating under a Seasonal Operation Period, the Resource Entity does not need to annually notify ERCOT of such status.

(8) A Resource Entity with a Mothballed Generation Resource operating under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to return the Mothballed Generation Resource to year-round operation by completing a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(9) A Resource Entity with a Mothballed Generation Resource that is not currently mothballed indefinitely must notify ERCOT in writing, by completing an NSO (Section 22, Attachment E), no less than 150 days before the date on which the Mothballed Generation Resource is to be suspended indefinitely or retired and decommissioned.

(10) ERCOT may request that a Mothballed Generation Resource operating under a Seasonal Operation Period be available for operation earlier than June 1st or later than September 30th of any given calendar year. If ERCOT identifies a specific Resource Entity or QSE with which it will discuss such a request in an attempt to reach a mutually agreeable resolution, ERCOT shall issue a Notice as soon as practicable. The Notice shall include the Resource name and, as applicable, the Resource mnemonic, the Resource MW Rating by Season, and the potential duration of the extended operation period, including anticipated start and end dates. If agreement is reached for the Mothballed Generation Resource to be available for operation earlier than June 1st or later than September 30th, the Resource Entity shall complete, within two Business Days, a Notification of Change of Generation Resource Designation form (Section 22, Attachment H).

(11) If ERCOT and the Resource Entity or QSE cannot reach a mutual agreement to make the Mothballed Generation Resource operating under a Seasonal Operation Period available earlier than June 1st or later than September 30th of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority.

(12) ERCOT may evaluate, on an annual basis, Mothballed Generation Resources operating under a Seasonal Operation Period for RMR Service to address ERCOT System reliability during the portion of the year when the Mothballed Generation Resource would be unavailable.

(13) A Resource Entity that submitted an NSO as a result of a Forced Outage must notify ERCOT of its intent to return to service as soon as practicable by updating its status in the Outage Scheduler and Current Operating Plan (COP) and is not required to submit a Notification of Change of Generation Resource Designation.

(14) Before retiring and decommissioning either a Mothballed Generation Resource this is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of Generation Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

(15) If a Generation Resource is designated as decommissioned and retired pursuant to any of the above provisions, ERCOT will permanently remove the Generation Resource from the ERCOT registration systems in accordance with Section 3.10.1. Except as provided in paragraph (16) below, if a Resource Entity decides to bring a Decommissioned Generation Resource back to service at a later date, it will be considered a new Resource and must follow the Generator Interconnection or Modification (GIM) process detailed in the Planning Guide. If the Generation Resource is designated as mothballed, ERCOT and TSPs will consider the Generation Resource mothballed until the Resource Entity indicates a definitive return to service date pursuant to this Section.

(16) A Resource Entity may bring a Decommissioned Generation Resource back to service without following the GIM process if the operating characteristics of the Resource are materially identical to the characteristics of the Resource as it existed prior to the date of decommissioning and the Resource Entity submits a Notification of Change of Generation Resource Designation (Section 22, Attachment H) within three years of the date the Generation Resource was removed from the ERCOT Network Operations Model. The date of return proposed in the Notification must be a Network Operations Model load date that is no earlier than 45 days and no later than 180 days from the date of the Resource Entity's Notification. ERCOT may delay the Network Operations Model load date based on the timing of the Resource Entity's submission of complete Resource registration data. If the Resource Entity is not the Resource Entity that was associated with the Generation Resource at the time it was removed from the model, the Resource Entity shall provide ERCOT documentation that establishes the Resource Entity's ownership of the Generation Resource.

(a) Notwithstanding the proposed date of return reflected in the Notification, as a condition for the synchronization of the Resource, ERCOT or the interconnecting Transmission and/or Distribution Service Provider (TDSP) may require any studies, testing, metering, or facility upgrades that ERCOT or the TDSP deem necessary for the reliable interconnection of the Resource, and ERCOT may require the Resource Entity to resolve any operational concern associated with the Resource. The TDSP may require the Resource Entity to compensate the TDSP for any required studies or upgrades in the same manner contemplated for new Generation Resources by the ERCOT Planning Guide, the TDSP's tariff, and the Standard Generation Interconnection Agreement (SGIA).

(b) If ERCOT or the TDSP requires any studies, testing, metering or facility upgrades, or if ERCOT determines that operational concerns must be addressed, the Resource Entity must complete the commissioning process within 90 days of the date of synchronization, subject to any extension authorized by ERCOT for good cause.

(c) Any Generation Resource that returns to service pursuant to this paragraph is entitled to any exemption from ERCOT requirements that the Resource was entitled to at the time it was removed from the model if the exemption still exists under ERCOT rules.

3.14.1.10 Eligible Costs

(1) "Eligible Costs" are costs that would be incurred by the RMR Unit owner to provide the RMR Service, excluding fuel costs or other costs the RMR Unit would have incurred anyway had it been mothballed or shut down.

(a) Examples of Eligible Costs include the following to the extent they each meet the standard for eligibility:

(i) Direct labor to operate the RMR Unit during the term of the RMR Agreement;

(ii) Materials and supplies directly consumed or used in operation of the RMR Unit during the term of the RMR Agreement;

(iii) Services necessary to operate the RMR Unit during the term of the RMR Agreement;

(iv) Costs associated with emissions credits used as a direct result of operation of the RMR Unit under direction from ERCOT, or emissions reduction equipment as may be required according to terms of the RMR Agreement;

(v) Costs associated with maintenance:

(A) Due to required equipment maintenance;

(B) Due to replacement to alleviate unsafe operating conditions;

(C) Due to regulatory requirements, with compliance dates during the term of the RMR Agreement (any such compliance dates and requirements shall be explicitly defined in the RMR Agreement); or

(D) To ensure the ability to operate the RMR Unit consistent with Good Utility Practice;

(vi) Reservation and transportation costs associated with firm fuel supplies not recovered under Section 6.6.6.2, RMR Payment for Energy;

(vii) Property taxes and other taxes attributable to continuing to operate the RMR Unit during the term of the RMR Agreement;

(viii) General fund transfers or similar direct expenses incurred by a Municipally Owned Utility (MOU) if it is required to pay a portion of its revenues to the municipality. If the RMR payment to the MOU is subject to such a requirement, this expense is an incremental cost directly associated with the RMR Unit;

(ix) Costs based on a long-term service agreement (LTSA), provided that:

(A) The maintenance costs to be included are incremental and consistent with the definitions of the costs within the scope of the RMR Agreement and these Protocols;

(B) The cost of each component is specifically set by the LTSA;

(C) ERCOT must be able to verify the incremental or variable maintenance costs ($/MWh) or ($/start) described in the LTSA; and

(D) The LTSA is in effect during the term of the RMR Agreement and available to ERCOT for review; and

(x) Non-fuel costs to return a mothballed RMR Unit to service provided that:

(A) The costs were incurred between the effective date of the RMR Agreement and the termination date of the RMR Agreement; and

(B) The costs do not include costs the RMR Unit would have incurred had it remained mothballed.

(b) Examples of costs not included as Eligible Costs are:

(i) Depreciation expense, return on equity, and debt and interest costs;

(ii) Property taxes and other taxes not attributable to continuing to operate the RMR Unit;

(iii) Income taxes of the RMR Unit owner or operator;

(iv) Labor and material costs associated with other, non-RMR Generation Resources at the same facility;

(v) Cost of parts inventory not used by the RMR Unit during the term of the Agreement;

(vi) Costs attributed to other Resources in the power generation station; and

(vii) Any other costs the Resource Entity that owns the RMR Unit would have incurred even if the RMR Unit had been mothballed or shutdown.

3.14.1.11 Budgeting Eligible Costs

(1) The owner of an RMR Unit shall provide a good faith preliminary budget, including detailed monthly estimates of its Eligible Costs to ERCOT, to support its calculation of the initial Standby Cost in Part III of the Notification of Suspension of Operations submitted to ERCOT pursuant to paragraph (4) of Section 3.14.1.2, ERCOT Evaluation Process, in a format acceptable to ERCOT. ERCOT shall review the budget and may reject any item it determines to be unreasonable. The owner of the RMR Unit and ERCOT may mutually agree to modify the expected contract capacity and Target Availability of the RMR Unit as necessary to account for any budget item that is rejected.

(2) As part of the MRA evaluation process, the QSE that represents the MRA must notify ERCOT if any contributed capital expenditures are required under the proposed MRA Agreement. The QSE that represents the MRA shall provide an explanation and a good faith preliminary budget for the contributed capital expenditures in a format acceptable to ERCOT. ERCOT shall review and may approve the budget to determine which costs would be considered contributed capital expenditures in accordance with Section 3.14.1.19, Charge for Contributed Capital Expenditures.

(3) ERCOT may retain a third party mutually agreeable to ERCOT and the owner of the RMR Unit to assist in the evaluation of a submitted budget, whether for initial or updated costs. The cost of such a third party will be allocated pursuant to paragraph (2) of Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

(4) The Eligible Cost budgeting process is as follows:

(a) The RMR Unit owner shall supply ERCOT a preliminary Eligible Cost budget for the expected RMR Agreement period starting with the anticipated effective date of the RMR Agreement.

(b) The preliminary Eligible Cost budget should be submitted in conjunction with Part III of the NSO, as specified in paragraph (2) of Section 3.14.1.1, Notification of Suspension of Operations, and paragraph (6) of Section 3.14.1.2.

(c) The budget will include Eligible Costs categorized in terms of:

(i) Base Cost of Operations, by month, which includes Eligible Costs that are independent of the levels of operation, Outages and non-Outage maintenance;

(ii) Outage Maintenance Cost, which includes Eligible Costs attributable to Planned or Maintenance Outages and/or inspections occurring during the term of the RMR Agreement, by month. Maintenance alternatives available during any Planned or Maintenance Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT's selection process. If no reasonable alternatives are available then the RMR Unit owner shall provide an affirmation to that effect;

(iii) Non-Outage Maintenance Cost, by month, which includes non-recurring Eligible Costs that are independent of a particular scheduled Outage. Non-Outage maintenance alternatives available during any scheduled Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT's selection process. If no reasonable alternatives are available then an affirmation by the RMR Unit owner to that effect must be included in the RMR Agreement;

(iv) For Resources without approved verifiable costs, the following data is required:

(A) Variable Operations & Maintenance (O&M) costs ($/start), from start to Low Sustained Limit (LSL), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(B) Operating variable O&M costs ($/MWh):

(1) At LSL; and

(2) Above LSL;

(C) Average generation from breaker close to LSL (MWh), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(D) Fuel consumption (MMBtu/start), for each start type:

(1) Cold;

(2) Hot; and

(3) Intermediate;

(E) Startup Fuel Percentage from start to LSL, for each start type:

Fuel Type	Hot (%)	Intermediate (%)	Cold (%)
Gas			
Fuel Oil			
Solid Fuel			

(F) Operating Fuel Percentage:

Fuel Type	At LSL	Above LSL
Gas		
Fuel Oil		
Solid Fuel		

(G) Input/output curve coefficients;

(v) Other budget items means Eligible Costs not clearly identifiable in the previous three categories including:

(A) Environmental emission credit consumption (or purchase as explicitly defined under the RMR Agreement, to operate the unit) includes the opportunity cost for using emission credits through the combustion of fuel feedstock by the RMR Unit. Costs must be based on verifiable market data as supplied by the RMR Unit owner; and

(B) "Compliance Costs," which includes foreseeable costs to comply with regulations, Federal or state that have a compliance deadline that occurs during the term of the RMR Agreement.

(d) Thirty days after receipt of the preliminary Eligible Costs budget, ERCOT shall notify the RMR Unit owner of its selections under the alternatives provided in the preliminary budget. The RMR Unit owner and ERCOT shall set the Target Availability monthly values consistent with the options presented to and selected by during the budgeting process. The Target Availability shall be mutually agreed by ERCOT and the RMR Unit owner by taking into account a negotiated amount of predicted Forced Outages, Planned Outages identified during the budgeting process, and any budget items rejected by ERCOT.

(e) If applicable, the RMR Unit owner should provide a written description of the type of work needed for the Resource to achieve the operational conditions for the RMR Service, in accordance with the capacity and Target Availability requirements. This should include:

(i) A description of the equipment needed;

(ii) An indication if the equipment is anticipated to be expensed or capitalized;

(iii) The estimated life and depreciation schedule of each capitalized component;

(iv) The estimated salvage value of the capitalized components;

(v) The estimated time to install each piece of equipment; and

(vi) The expected time of completion of work needed to restore the Resource to operational status.

3.14.1.12 Calculation of the Initial Standby Cost

(1) The initial Standby Cost shall be calculated by dividing the total monthly approved budget cost over the term of the RMR Agreement by the total hours for the term of the RMR Agreement.

3.14.1.13 Updated Budgets During the Term of an RMR Agreement

(1) Upon commencement of the RMR Agreement, based on the Agreement term, the RMR Unit owner shall identify planned equipment installations as anticipated to be expensed or capitalized and shall update the estimated salvage value of capitalized components. The RMR Unit owner shall submit to ERCOT updated budget information every three months, in a format consistent with the preliminary budget, for the remainder of the term of the RMR Agreement. ERCOT shall review updated budget information for reasonableness and may reject any item it determines to be unreasonable. The owner of the RMR Unit and ERCOT may mutually agree to modify the contract capacity and Target Availability of the RMR Unit to account for any such budget item rejection.

(2) ERCOT will use approved updated budget information to update the total RMR costs expected to be incurred over the remaining term of the RMR Agreement. If the total costs over the remaining term of the RMR Agreement change by more than 10% with respect to those costs anticipated for the same period in the most recently approved budget, the RMR Standby Cost will be recalculated. The revised Standby Cost will be

recalculated by dividing the remaining budgeted costs over the number of remaining hours for which the RMR Unit is under an RMR Agreement.

(3) ERCOT shall issue a Market Notice describing the revised Standby Cost at least ten calendar days prior to the effective date of a change to the Standby Cost. The effective date of a revised Standby Cost will always be on the first day of a calendar month.

3.14.1.14 Reporting Actual RMR Eligible Costs

(1) The RMR Unit owner shall provide ERCOT with documentation supporting actual Eligible Costs on a monthly basis in a form and a level of detail acceptable to ERCOT for ERCOT to verify that all Eligible Costs are actual and appropriate. Submitted actual Eligible Costs must be categorized consistently with budgeted Eligible Costs. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the Final or True-Up Settlement Statement.

(2) To be considered timely for the final, actual cost data for month 'x' must be submitted by the 16th of the month following month 'x'. To be considered timely for the true-up, actual cost data for month 'x' must be submitted 60 days prior to the publishing date of the True-Up Settlement Statement for the first day in month 'x'. Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event, that actual cost data is not submitted in accordance with the calendar or approved deviation for the true-up, then the cost for the portion of eligible cost that has not been submitted is deemed to be zero.

3.14.1.15 Reporting Actual MRA Eligible Costs

(1) The QSE that represents the MRA that has received contributed capital expenditures shall provide ERCOT with evidence of the actual costs associated with the capital expenditures on a monthly basis in a level of detail sufficient for ERCOT to verify that all capital contributions costs are actual and appropriate.

3.14.1.16 Reconciliation of Actual Eligible Costs

(1) ERCOT shall issue a miscellaneous Invoice to charge the QSE representing the RMR Unit for any identified over-payments for actual Eligible Costs. Funds collected will be distributed in accordance with Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

3.14.1.17 Incentive Factor

(1) Subject to the reductions described in paragraphs (2) and (3) below, the Incentive Factor for RMR Agreements is equal to 10% of the actual Eligible Costs, excluding fuel costs and reservation and transportation costs associated with firm fuel supplies as described in paragraph (1)(a)(vi) of Section 3.14.1.10, Eligible Costs. The Incentive Factor for RMR Agreements is not applied to capital expenditures as described in Section 3.14.1, Reliability Must Run, or to capital expenditures reclassified as an expense in accordance with paragraph (3)(d) of Section 3.14.1.19, Charge for Contributed Capital Expenditures. The Incentive Factor shall never be less than zero.

(2) The Incentive Factor shall be reduced if the RMR Unit fails to perform to the contracted capacity during a Capacity Test as described in the RMR Agreement. The reduction will be linear, with a 2% reduction in the Incentive Factor for every 1% of reduced Capacity.

(3) The Incentive Factor shall be reduced if the "Hourly Rolling Equivalent Availability Factor" of the RMR Unit is less than the Target Availability (i.e. the "Actual Availability", as defined below, is less than the Target Availability).

(a) The reduction will be linear; with a 2% reduction in the Incentive Factor payment for every 1% of the Hourly Rolling Equivalent Availability Factor less than the Target Availability stated in the RMR Agreement. The RMR Unit's Actual Availability shall be calculated on an hourly rolling six-month average basis.

(b) The calculation is made by dividing the total MW of available capacity per hour according to its final COP by the total MW of contracted capacity per hour for the previous 4380 hours.

(c) For purposes of this calculation, any hour within the previous 4380-hour period that precedes the start date of the RMR Agreement is treated as if 100% of the capacity of the unit was available for the hour.

3.14.1.18 Major Equipment Modifications

(1) During the term of an RMR Agreement, in the event that major equipment modifications are required in order for the RMR Unit to provide RMR Service (such as installation of environmental control equipment), ERCOT and the RMR Unit owner shall negotiate in good faith concerning changes to the terms of the RMR Agreement.

3.14.1.19 Charge for Contributed Capital Expenditures

(1) This Section applies to any RMR or MRA Agreement entered into by ERCOT and a Resource Entity or QSE on or after October 12, 2016.

(2) For purposes of this Section, contributed capital expenditures are defined as expenditures that were made to ensure the availability of an RMR Unit or MRA in connection with an

RMR or MRA Agreement, that were settled in accordance with the Settlement processes in the ERCOT Protocols, and that would ordinarily be capitalized under Generally Accepted Accounting Principles (GAAP) or International Accounting Standards (IAS) assuming ongoing operation of the RMR Unit or MRA. Consistent with the process described in Section 3.14.1.11, Budgeting Eligible Costs, ERCOT will identify contributed capital expenditure items included in each category of submitted Eligible Costs as defined in Section 3.14.1.10, Eligible Costs, or submitted with any MRA budgets.

(3) A QSE that has received payments from ERCOT for contributed capital expenditures pursuant to an RMR or MRA Agreement entered into on or after October 12, 2016 must refund to ERCOT the contributed capital expenditures as follows:

(a) At the end of the RMR Agreement, if the Resource Entity chooses not to have the Generation Resource participate in energy or Ancillary Service markets, the QSE representing the Resource Entity shall repay, in a lump sum payment, the positive salvage value associated with the contributed capital expenditures, as estimated at the time of the RMR Agreement.

(b) At the end of the MRA Agreement, if the QSE that represents the MRA chooses not to have the MRA participate in energy or Ancillary Service markets, the QSE representing the MRA shall repay, in a lump sum payment, the positive salvage value associated with the contributed capital expenditures, as estimated at the time of the MRA Agreement. In addition, the QSE that represents the MRA must repay, in a lump sum payment, the value of contributed capital expenditures in excess of the actual cost of the capitalized equipment.

(c) If an RMR Unit or MRA participates in the energy or Ancillary Service markets at any time after the termination date of the RMR or MRA Agreement, the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA shall repay, in a lump sum payment, 100% of the remaining book value of the capitalized equipment and capitalized installation charges based on straight-line depreciation over the estimated life of the capitalized component(s) as of the termination date of the RMR or MRA Agreement in accordance with GAAP or IAS standards for electric utility equipment, plus 10% of the value of any accelerated tax depreciation associated with the capital contribution taken by the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA during the term of the RMR or MRA Agreement, less any remaining positive salvage value associated with the contributed capital expenditures that was previously repaid in accordance with paragraph (a) or (b) above. The estimated life shall be based on documentation provided by the manufacturer; or, if installing used equipment, the estimated life may be based on an approximation agreed to by the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA and ERCOT, but in no event shall the estimated life be less than the equipment life used for federal income tax purposes. The value of the accelerated tax depreciation for each year shall be the difference between the straight line figure and the appropriate Modified Accelerated Cost Recovery

System (MACRS) depreciation schedule for the equipment, multiplied by the statutory tax rate. The calculation of the accelerated depreciation as described herein must be supported by an attestation executed by an officer or executive with the authority to bind the Resource Entity or the QSE representing the Resource Entity.

(d) If additional contributed capital expenditures are identified subsequent to execution and during the term of the RMR or MRA Agreement, the applicable repayment amounts as determined in paragraphs (a), (b), or (c) above will be modified accordingly.

(e) The amount of contributed capital expenditures may be adjusted by ERCOT when early termination in accordance with the RMR Agreement results in a reclassification of capital expenditures to expenses in accordance with GAAP or IAS.

(f) If the Resource Entity that owns or controls the RMR Unit or the QSE that represents the MRA is required to pay a lump sum payment of contributed capital expenditures per paragraph (a), (b), or (c) above, then ERCOT will issue a Market Notice identifying the amount of the lump sum payment within five Business Days of termination of the RMR or MRA Agreement.

(i) ERCOT shall issue a miscellaneous Invoice charging the QSE for the applicable amounts under paragraphs (a), (b), or (c) above. ERCOT will issue a Market Notice after completion of the collection and disbursement of the repaid contributed capital expenditures.

(ii) ERCOT shall distribute the repayment to QSEs representing Load per Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses.

3.14.1.20 Budgeting Fuel Costs

(1) The RMR Unit owner shall supply ERCOT a preliminary monthly fuel cost budget for the anticipated term and effective date of the RMR Agreement. The fuel cost budget must include information pertaining to the cost of the fuel feedstock, including where appropriate transportation costs and terms, as well as fuel storage costs and terms, and any other fuel contract provisions (e.g. “take or pay” provisions) that may impact the cost of all fuels anticipated to be used by the RMR Unit over the life of the RMR Agreement and must include fuel costs categorized in terms of:

(a) Primary fuel; and

(b) Secondary fuel.

(2) The estimated fuel payments may include a fuel adder to better approximate expected fuel costs, which may be adjusted from time to time by mutual agreement of the RMR Unit owner and ERCOT. The fuel adder shall represent the difference between the forecasted average fuel price and the forecasted average of the relevant index price over the RMR contract period. The fuel adder must also include the forecasted cost of transporting and delivering fuel and fuel imbalance fees to the Resource. The RMR Unit owner must provide to ERCOT supporting documentation indicating how the fuel adder was determined.

(3) The RMR Unit owner shall provide good faith estimates of the RMR Unit input/output curve coefficients to ERCOT with its Notification of Suspension of Operations.

(4) Based on production figures provided to the RMR Unit owner by ERCOT, the RMR Unit owner shall also provide ERCOT fuel supply options available for the RMR Unit. For each option, the RMR Unit owner shall detail the associated impacts on the fuel and non-fuel budgets and on the availability of the RMR Unit. If no reasonable alternatives are available then an affirmation by the RMR Unit owner to that effect must be included in the RMR Agreement. If there are available fuel options, then no less than 30 days after the receipt of the fuel supply options, ERCOT shall notify the RMR Unit owner of its fuel supply option selection.

3.14.1.21 Reporting Actual Eligible Fuel Costs

(1) The RMR Unit owner shall provide ERCOT with actual fuel costs on a monthly basis for the RMR Unit in a level of detail sufficient for ERCOT to verify that all fuel costs are actual and appropriate. ERCOT shall perform a true-up of the estimated fuel costs using the submitted and verified actual fuel costs for the RMR Unit. Actual cost data must be submitted on time by the Resource Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 16th of the month following month ‘x.’ To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 60 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x.’ Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR Unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. No later than two Business Days following its decision, ERCOT shall issue a Market Notice of any such request and its response thereto. In the event that actual cost data is not submitted in accordance with the timeline or is not an approved deviation for the true-up, then the cost for the portion of Eligible Cost that has not been submitted is deemed to be zero.

(2) Actual fuel costs must be appropriate actual costs attributable to ERCOT’s scheduling and/or deployment of the RMR Unit. Actual fuel costs may include cost of fuel (including the cost of exceeding swing gas contract limits, additional gas demand costs set by fuel supply, or transportation contracts); demand fees, imbalance penalties,

transportation charges, and cash out premiums. In addition, actual fuel costs may include costs incurred to:

(a) Keep the boiler(s) warmed, if approved in advance by ERCOT; and

(b) Test the RMR Unit prior to or during the term of the RMR Agreement, if approved in advance by ERCOT.

3.14.2 Black Start

(1) Each Generation Resource providing BSS must meet the requirements specified in North American Electric Reliability Corporation (NERC) Reliability Standards and the Operating Guides.

(2) Each Generation Resource providing BSS must meet the technical requirements specified in Section 8.1.1, QSE Ancillary Service Performance Standards, and Section 8.1.1.1, Ancillary Service Qualification and Testing.

(3) Bids for BSS are due on or before February 15th of each three-year period. Bids must be evaluated based on evaluation criteria attached as an appendix to the request for bids and contracted by December 31st for the following three-year period. ERCOT shall ensure BSSs are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a Blackout or Partial Blackout.

(a) Resources shall disclose any weather-related limitations that could affect the Resource’s ability to provide BSS using the form provided in Section 22, Attachment M, Generation Resource Disclosure Regarding Bids for Black Start Service, as part of a bid to provide BSS.

(b) BSS bids shall include the hourly stand-by price and the BSS Back-up Fuel costs where applicable.

(c) When a Resource is selected to provide BSS, the Black Start Resource shall be required to complete all applicable testing requirements as specified in Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing.

(d) ERCOT shall provide a list of all prospective Black Start Resources that responded to the RFP for BSS to the impacted TSPs no later than seven days after the date on which bids for BSS are due. Any feedback from affected TSPs shall be limited to the identification of transmission constraints that may adversely impact the ability of the Black Start Resource to energize the Next Start Resource and shall be due to ERCOT by March 1st of that year. ERCOT shall share the feedback with the QSE representing the prospective Black Start Resource as soon as practicable. The QSE representing the Black Start Resource shall have the option to provide a response to any feedback provided by an affected TSP.

(4) ERCOT may schedule unannounced Black Start testing, to verify that BSS is operable as specified in Section 8.1.1.2.1.5.

(5) QSEs representing Generation Resources contracting for BSSs shall participate in training and restoration drills coordinated by ERCOT.

(6) ERCOT shall periodically determine and review the location and number of Black Start Resources required, as well as any special transmission or voice communication needs required. ERCOT and providers of this service shall meet the requirements as specified in the Operating Guides and in NERC Reliability Standards.

(7) A Resource Entity representing a Black Start Resource may request that an alternate Generation Resource which is connected to the same black start primary and secondary cranking path as the original Black Start Resource be substituted in place of the original Black Start Resource during the three year term of an executed Standard Form Black Start Agreement (Section 22, Attachment D, Standard Form Black Start Agreement) if the alternate Generation Resource meets testing and verification under established qualification criteria to ensure BSS.

(a) ERCOT, in its sole discretion, may reject a Resource Entity's request for an alternate Generation Resource and will provide the Resource Entity an explanation of such rejection.

(b) If ERCOT accepts the alternative Generation Resource as the substituted Black Start Resource, such acceptance shall not affect the original terms, conditions and obligations of the Resource Entity under the Standard Form Black Start Agreement. The Resource Entity shall submit to ERCOT an Amendment to Standard Form Black Start Agreement (Section 22, Attachment I, Amendment to Standard Form Black Start Agreement) after qualification criteria has been met.

(8) For the purpose of the Black Start Hourly Standby Fee as described in Section 6.6.8.1, Black Start Hourly Standby Fee Payment, the Black Start Service Availability Reduction Factor shall be determined by using the availability for the original Black Start Resource and any substituted Black Start Resource(s), as appropriate for the rolling 4380-hour period of the evaluation.

(9) Each Generation Resource selected to provide BSS shall be prepared and able to provide BSS at any time as may be required by ERCOT, subject only to the limitations described in ERCOT Protocols or the Black Start Agreement.

(10) Each Generation Resource selected to provide BSS shall be able to utilize BSS Back-up Fuel for BSS and shall maintain a contracted amount of BSS Back-up Fuel to run the Black Start Resource for a minimum of 72 hours at its maximum output. The Generation Resource shall maintain the contracted amount of BSS Back-up Fuel at all times during the duration of the BSS contract term unless performing a BSS Back-up Fuel Switching Test or the Generation Resource is operating pursuant to a Black Start deployment event. This requirement does not apply to Resources that do not rely on purchased fuel.

(11) A Black Start Resource may utilize the contracted amount of BSS Back-up Fuel outside of BSS if ERCOT determines it is necessary during an Energy Emergency Alert (EEA) event.

(12) A Black Start Resource is not obligated to contract its full on site fuel storage capability for BSS Back-up Fuel. On site backup fuel in excess of the contracted BSS Back-up Fuel amount may be used by the Generation Resource at the discretion of the Generation Resource and ERCOT shall not prevent the Black Start Resource from utilizing the excess fuel, nor shall the Black Start Resource be required to request permission from ERCOT to utilize fuel in excess of the contracted BSS Back-up Fuel amount.

(13) ERCOT may, at its discretion, waive the BSS Back-up Fuel requirement stated in this Section, in whole or in part, if ERCOT deems necessary in order to procure a sufficient number or preferred combination of Generation Resources to provide BSS.

(14) A Resource Entity that submits a bid or is contracted to provide BSS or serve as an alternate to provide BSS with a Switchable Generation Resource (SWGR):

(a) Shall not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the term of the BSS contract;

(b) Shall submit a report to ERCOT in compliance with paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information, indicating that the SWGR does not have any contractual requirement in a non-ERCOT Control Area during the term of the BSS contract; and

(c) Shall take any further action requested by ERCOT to ensure that ERCOT will be classified as the "Primary Party" for the SWGR under any agreement between ERCOT and another Control Area Operator during the term of the BSS contract.

(15) If a Resource Entity with a SWGR is contracted to provide BSS or designated as an alternate to provide BSS, the Resource Entity shall have its Black Start plan procedures approved by ERCOT. In the event of a Partial Blackout or Blackout of the ERCOT System, the Resource Entity with a SWGR shall immediately:

(a) Effectuate its Black Start plan procedures to be available to provide BSS; and

(b) Provide BSS as directed by ERCOT or the local Transmission Operator (TO).

3.14.3 Emergency Response Service

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

3.14.3.1 Emergency Response Service Procurement

(1) ERCOT shall issue Requests for Proposals to procure ERS for each Standard Contract Term. The ERS Standard Contract Terms are as follows:

  (a) December through March;

  (b) April and May;

  (c) June through September; and

  (d) October and November.

(2) ERCOT shall procure ERS from one or more of the four following ERS service types:

  (a) Weather-Sensitive ERS-10

  (b) Non-Weather-Sensitive ERS-10

  (c) Weather-Sensitive ERS-30

  (d) Non-Weather-Sensitive ERS-30

(3) ERS offers shall be submitted only by QSEs capable of receiving both Extensible Markup Language (XML) messaging and Verbal Dispatch Instructions (VDIs) on behalf of represented ERS Resources.

(4) Each site in an ERS Generator must have an interconnection agreement with its Transmission and/or Distribution Service Provider (TDSP) prior to submitting an ERS offer and must have exported energy to the ERCOT System prior to the offer due date. An ERS Resource that cannot inject energy to the ERCOT System can only be offered as an ERS Load.

(5) In order to qualify as weather-sensitive, an ERS Load must meet one of the following criteria:

  (a) The ERS Load must consist exclusively of residential sites; or

  (b) The ERS Load must consist exclusively of non-residential sites and must qualify as weather-sensitive based on the accuracy of the regression baseline evaluation methodology as described in Section 8.1.3.1.1, Baselines for Emergency Response Service Loads, as an indicator of actual interval Load.

    (i) ERCOT shall establish minimum accuracy standards for qualification as an ERS Load under the regression baseline evaluation methodology.

    (ii) An ERS Load must have at least nine months of interval meter data to qualify as weather-sensitive under the regression baseline evaluation methodology.

(iii) ERCOT's determination that an ERS Load qualifies as a weather-sensitive ERS Load is independent of ERCOT's determination of which baseline methodologies may be appropriate for purposes of evaluating the ERS Load's performance.

(c) If a site with Distributed Renewable Generation (DRG) has been designated by the QSE to be evaluated by using its native load, the default baseline analysis shall be performed using the calculated native load.

(6) QSEs representing ERS Resources may submit offers for one or more ERS Time Periods within an ERS Standard Contract Term. ERS Time Periods shall be defined by ERCOT in the RFP for that ERS Standard Contract Term. An ERS offer is specific to an ERS Time Period. In submitting an offer, both the QSE and the ERS Resource are committing to provide ERS for that ERS Time Period if selected.

(7) A QSE may submit separate offers for an ERS Resource to provide any or all of the four ERS service types during the same or different ERS Time Periods in the same ERS Standard Contract Term, but ERCOT shall only award offers for one service type for each ERS Resource.

(8) The minimum capacity offer for an ERS Load on the weather-sensitive baseline is one half (0.5) MW; all other ERS capacity offers will have a minimum amount that may be offered of one-tenth (0.1) MW. ERS Resources may be aggregated to reach this requirement.

(9) Offers from ERS Generators must include self-serve capacity and injection capacity amounts greater than or equal to zero for each ERS Time Period offered.

(10) ERCOT may establish an upper limit, in MWs, on the amount of ERS capacity it will procure for any ERS Time Period in any ERS Standard Contract Term.

(11) A QSE's offer to provide ERS shall include:

(a) The name of the QSE representing the ERS Resource and the name of an individual authorized by the QSE to represent the QSE and its ERS Resource(s);

(b) The name of an Entity that controls the ERS Resource, and an affirmation that the QSE has obtained written authorization from the Entity to submit ERS offers on its behalf and to represent the Entity in all matters before ERCOT concerning the Entity's provision of ERS;

(c) Any information or data specified by ERCOT, including access to historical meter data, and affirmation by the QSE that it has obtained written authorization from the controlling Entity of the ERS Resource for the QSE to obtain such data;

(d) Affirmation that the controlling Entity of the ERS Resource has reviewed P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), these Protocols and Other Binding Documents relating to the provision of ERS, and has agreed to comply with and be bound by such provisions;

(e) An agreement by the QSE to produce any written authorization or agreement between the QSE and any ERS Resource it represents, as described in this Section, upon request from ERCOT or the PUCT;

(f) Affirmation that no offered capacity from any site in an ERS Resource has been or will be committed to provide any other product, service, or program during any of the hours in the ERS Time Period in the Standard Contract Term for which the offer is submitted. Such prohibited products, services, or programs include, but are not limited to, Ancillary Services, Security-Constrained Economic Dispatch (SCED), or TDSP standard offer programs. As an exception to the foregoing, a QSE may offer a site to provide ERS for an ERS Time Period in the Standard Contract Term even if the QSE has an offer pending for that same site to serve as an MRA during that ERS Time Period and Standard Contract Term; however, if the site is selected to serve as an MRA it will not be permitted to serve as ERS during any ERS Time Period in the ERS Contract Term in which it is obligated to serve as an MRA;

(g) Affirmation that the QSE and the controlling Entity the ERS Resource are familiar with any applicable federal, state or local environmental regulations that apply to the use of any generator in the provision of ERS, and that the use of such generator(s) to provide of ERS would not violate those regulations. This provision applies to both ERS Generators and to the use of backup generation by ERS Loads; and

(h) Affirmation that each offered ERS Resource satisfies at least one of the conditions set forth in paragraph (9) of Section 3.6.1, Load Resource Participation, and that all of the ERS Resource's offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(12) Upon request from a QSE, ERCOT shall provide the dates and times for any deployment events or tests of any ERS site during the previous three ERS Standard Contract Terms, provided that the QSE has obtained written authorization from the ERS site to obtain the information from ERCOT. Such QSE requests shall include the following site-specific information: Electric Service Identifier (ESI ID), unique meter identifier (if applicable), or, if the site is in a Non-Opt-In Entity (NOIE) area, site name and site address.

(13) Sites associated with a Dynamically Scheduled Resource (DSR) may not participate in ERS. Offers for Resources containing sites associated with a DSR will be rejected by ERCOT. If ERCOT determines that any participating site is associated with a DSR, that site will be treated as removed from the Resource on the date the determination was made. An ERS Resource's obligation will not change as a result of any such site removal.

[NPRR1000: Delete item (13) above upon system implementation and renumber accordingly.]

(14) Each offer submitted by a QSE on behalf of an aggregated ERS Load on a weather-sensitive baseline shall include the QSE's projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term. ERCOT shall review this projection and the information provided regarding the initial size of each aggregated ERS Load and shall reject any offer on behalf of such an ERS Load if the maximum size of the ERS Load projected by the QSE would violate the limits of site participation growth described in paragraph (15) below.

(15) A QSE may modify the population of an aggregated ERS Load on a weather-sensitive baseline once per month during an ERS Standard Contract Term via a process defined by ERCOT. Such adjustments shall be effective on the first day of each month following the first month. A fully validated ERS Offer form must be received by ERCOT no later than seven business days prior to the first day of the month for which is intended to be in effect.

(a) During an ERS Standard Contract Term, a QSE may increase the number of sites in an aggregated ERS Load on a weather-sensitive baseline by no more than the greater of the following:

(i) 100% of the initial number of sites; or

(ii) Two MW times the QSE's projection of the maximum number of sites in the aggregation during the ERS Standard Contract Term, divided by the maximum MW capacity offered for any ERS Time Period for the aggregation.

(b) Any sites added to an ERS Load on a weather-sensitive baseline are subject to the same requirements for historical meter data as the other sites in the aggregation, as described in paragraph (4) of Section 8.1.3.1.1.

(16) For each of the four ERS service types, an ERS Standard Contract Term may consist of a single ERS Contract Period or multiple non-overlapping ERS Contract Periods, as follows:

(a) If no ERS Resources' obligations are exhausted for an ERS service type during an ERS Contract Period pursuant to Section 3.14.3.3, Emergency Response Service Provision and Technical Requirements, the ERS Contract Period for that ERS service type shall terminate at the end of the last Operating Day of the ERS Standard Contract Term.

(b) If one or more ERS Resources' obligations in a given ERS service type are exhausted pursuant to Section 3.14.3.3, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day during which the exhaustion occurred. However, if ERS Resources participating in a service type remain deployed at the end of that Operating Day, the ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day on which those ERS Resources are recalled.

(c) If an ERS Contract Period terminates as provided in paragraph (b) above, and one or more ERS Resources' obligations were not exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the following Operating Day. This new ERS Contract Period shall terminate as provided in this Section.

(d) If ERCOT elects pursuant to paragraph (b) above to renew the obligations of any ERS Resources whose obligations were entirely exhausted, a new ERS Contract Period for the ERS service type shall begin at hour ending 0100 on the Operating Day after ERCOT has notified QSEs that it has elected to renew the obligation. If a new ERS Contract Period was initiated pursuant to paragraph (c) above on an Operating Day prior to ERCOT issuing a notice of renewal under this paragraph, that ERS Contract Period shall terminate at the end of the Operating Day on which ERCOT notified QSEs that the renewal will take place. This new ERS Contract Period shall terminate as provided in this Section.

(17) An ERS Resource currently obligated to provide an ERS service type during an ERS Time Period and ERS Contract Period may be offered to provide service as an MRA during that same ERS Time Period in the ERS Contract Period. If the ERS Resource is selected to provide service as an MRA during an ERS Time Period in the ERS Contract Period in which it is currently obligated to provide an ERS service type, the ERS Contract Period will be terminated for that ERS service type. The ERS Contract Period for that ERS service type shall terminate at the end of the Operating Day that is five days before the first Operating Day the ERS Resource is obligated to provide service under the MRA Agreement. However, if any ERS Resources participating in that ERS service type are currently deployed at the end of the Operating Day the ERS Contract Period is scheduled to terminate, then the ERS Resource's ERS Contract Period for that ERS service type shall continue until the end of the Operating Day on which all of the ERS Resources participating in that ERS service type have been recalled, at which time the ERS Contract Period will terminate.

(18) ERS Resources shall be obligated in ERS Contract Periods as follows:

(a) Unless an ERS Contract Period is terminated pursuant to paragraph (17) above, for the first ERS Contract Period in an ERS Standard Contract Term, all ERS Resources awarded by ERCOT shall be obligated.

(b) ERS Resources shall be obligated for 24 hours of cumulative deployment time for any ERS Contract Period during the December through March ERS Standard Contract Term. The obligated cumulative deployment time for any ERS Contract Period during all other ERS Standard Contract Terms shall be 12 hours.

(c) For each of any subsequent ERS Contract Periods for a given ERS service type in an ERS Standard Contract Term, any ERS Resource with remaining obligation due to cumulative deployment time of less than the maximum deployment hours specified for the ERS Standard Contract Term in paragraph (b) above at the end of the last ERS Contract Period shall be obligated for only this remaining deployment time in the new ERS Contract Period.

(d) For each of any subsequent ERS Contract Periods in an ERS Standard Contract Term, ERCOT may renew the obligations of certain ERS Resources as follows:

(i) During the offer submission process, QSEs shall designate on the ERS offer form, which is posted on the ERCOT website, whether an ERS Resource elects to participate in renewal ERS Contract Periods ("renewal opt-in"). Except as provided in paragraph (iv) below, this election is irrevocable once the ERS Resource has been committed for an ERS Standard Contract Term.

(ii) If the obligations of one or more ERS Resources are exhausted before the end of an ERS Standard Contract Term, ERCOT shall determine whether to include renewal opt-ins in the subsequent ERS Contract Period. ERCOT may limit any renewal to one or more ERS Time Periods and/or a specified MW quantity in which obligations have been exhausted.

(iii) If ERCOT decides to include renewal opt-ins in a subsequent ERS Contract Period, ERCOT shall promptly notify all ERS QSEs as to the ERS Time Periods and/or any specified MW quantity that it has elected to renew.

(iv) By the end of the second Business Day in any renewal ERS Contract Period, a QSE may revoke the renewal opt-in status of any of its committed ERS Resources for any subsequent ERS Contract Periods within that ERS Standard Contract Term. ERCOT shall develop a method for QSEs to communicate such information.

(v) By the end of the third Business Day in any ERS Contract Period other than the first ERS Contract Period in an ERS Standard Contract Term, ERCOT shall communicate to QSEs a confirmation of the terms of participation for all of their committed ERS Resources.

(19) In any 12-month period beginning on December 1st and ending on November 30th, ERCOT shall not commit dollars toward ERS in excess of the ERS cost cap, except for the purpose of renewing ERS Resource obligations during a period where ERS has been exhausted. ERCOT may determine cost limits for each ERS Standard Contract Term in order to ensure that the ERS cost cap is not exceeded.

(20) If a QSE offers a Weather-Sensitive ERS Load, selects a control group baseline for that ERS Load, and ERCOT determines that the magnitude of the offer relative to the baseline

error will prevent accurate determination of the performance, ERCOT shall reject the offer.

(21) ERCOT shall reduce the available expenditure under the ERS cost cap by the value of the amount of ERS Self-Provision. ERCOT shall value ERS Self-Provision at the clearing price multiplied by the total MW of ERS Self-Provision during each relevant ERS Time Period.

(22) ERCOT shall procure ERS Resources for each ERS Time Period using a clearing price. The Emergency Response Service Procurement Methodology, posted on the ERCOT website, is an Other Binding Document that describes the methodology used by ERCOT to procure ERS. ERCOT may consider geographic location and its effect on congestion in making ERS awards. ERCOT may prorate the capacity awarded to an ERS Resource in an ERS Time Period if the capacity offered for that ERS Resource would cost more than the Emergency Response Service Procurement Methodology allows under the time period expenditure limit. Such proration shall only be done if the QSE indicates on its offer for an ERS Resource that the QSE is willing to have the capacity prorated and also has indicated the lowest prorated capacity limit which is acceptable for that ERS Resource. If proration would result in an award below an ERS Resource’s designated prorated capacity limit or below the minimum MW offer applicable to the ERS service type as specified in paragraph (8) above, the offer will not be awarded.

(23) Payments and Self-Provision credits to QSEs representing ERS Resources are subject to adjustments as described in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities. Deployment of ERS Resources will not result in additional payments other than any payment for which the QSE may be eligible through Real-Time energy imbalance or other ERCOT Settlement process.

(24) QSEs representing ERS Resources selected to provide ERS shall execute a Standard Form Emergency Response Service Agreement, as provided in Section 22, Attachment G, Standard Form Emergency Response Service Agreement.

3.14.3.2 Emergency Response Service Self-Provision

(1) QSEs may self-provide ERS. A QSE electing to self-provide all or part of its ERS obligation shall provide ERCOT with the following, while adhering to a schedule published by ERCOT:

(a) The maximum MW of capacity the QSE is willing to self-provide for each ERS Time Period for each of the four ERS service types; and

(b) A proxy Load Ratio Share (LRS) specific to each ERS Time Period for which an offer is submitted. Proxy LRS shall be a number between zero and one and determined by the self-providing QSE to represent its estimate of its final LRS to be used in ERS Settlement.

(2) ERS Self-Provision Capacity Upper Limit is defined as the maximum level of self-provided ERS MW capacity for which a QSE may receive credit at Settlement for each ERS service type. During the procurement process, a QSE may elect to use a proxy ERS Self-Provision Capacity Upper Limit (based on the proxy LRS it submitted) to reduce its ERS Self-Provision MW for each ERS service type. After receiving ERS Self-Provision information, ERCOT will award offers for additional MWs of ERS capacity for each ERS service type such that the sum of the following does not exceed the total amount of ERS capacity ERCOT intends to procure for that ERS service type in any one ERS Time Period:

(a) ERS capacity awarded through ERS competitive offers; and

(b) ERS capacity awarded through ERS Self-Provision offers, where for each self-providing QSE the self-provided capacity offer is the lesser of the amount offered or the QSE's proxy ERS Self-Provision Capacity Upper Limit.

(3) The calculations used to determine a QSE's proxy ERS Self-Provision Capacity Upper Limit for each ERS service type for the ERS procurement phase are the same as those used to determine the actual ERS Self-Provision Capacity Upper Limit for Settlement, as described in Section 6.6.11.1, Emergency Response Service Capacity Payments, except that:

(a) Offered ERS capacity is substituted for delivered ERS capacity; and

(b) A QSE's proxy LRS is substituted for its actual LRS.

(4) ERCOT shall compute and provide QSEs offering ERS Self-Provision their proxy ERS Self-Provision Capacity Upper Limit for each ERS service type. A QSE may then reduce any or all of its self-provision offers such that its revised total ERS Self-Provision capacity is greater than or equal to its proxy ERS Self-Provision Capacity Upper Limit provided by ERCOT.

(5) A QSE with reduced ERS Self-Provision capacity shall notify ERCOT of the ERS Resources whose obligations are reduced and the quantity of the revised obligations. The QSE must provide this information to ERCOT within two Business Days of receiving Notice of the reduced obligation.

(6) If a QSE reduces its ERS commitment according to these procedures, it will not be obligated to pay ERS charges so long as the ERS Self-Provision capacity it delivers is equal to or greater than its final LRS of the total ERS capacity delivered through offers and ERS Self-Provision, as described in paragraph (2) of Section 6.6.11.2, Emergency Response Service Capacity Charge.

(7) A QSE opting for ERS Self-Provision may also offer separate capacity into ERS in the form of a priced offer in the same manner as any other QSE.

(8) The capacity obligation of a self-provided ERS Resource that is designated for renewal opt-in, as described in paragraph (18) of Section 3.14.3.1, Emergency Response Service

Procurement, will be fixed at the original awarded MW level for any subsequent ERS Contract Periods in the ERS Standard Contract Term.

3.14.3.3 Emergency Response Service Provision and Technical Requirements

(1) If ERCOT deploys ERS, any ERS Resource that is contractually committed to provide the ERS service type deployed during the ERS Time Period that includes all or any part of the first interval of the Sustained Response Period must deploy. If an ERS Resource does not have an obligation for any part of the first interval of the Sustained Response Period, the ERS Resource is not required to deploy at any time during the Sustained Response Period.

(2) For purposes of this paragraph, deployment obligation time is the cumulative time during the Sustained Response Period of an event during which an ERS Resource has an obligation. Deployment obligation time does not include the ramp time. An ERS Resource shall be subject to the maximum cumulative deployment obligation time for an ERS Contract Period as specified in paragraph (18)(b) of Section 3.14.3.1, Emergency Response Service Procurement, except that for ERS Resources that did not exhaust their obligations in a previous ERS Contract Period within the same ERS Standard Contract Term, the maximum deployment obligation time shall be the remaining deployment obligation time from the previous ERS Contract Period as provided by paragraph (18)(c) of Section 3.14.3.1. Weather-Sensitive ERS test deployments do not contribute to the calculation of cumulative deployment obligation time.

(3) Notwithstanding paragraph (1) above, the following apply:

(a) For a Weather-Sensitive ERS Resource, the following shall apply:

(i) The maximum number of deployment events during an ERS Contract Period shall be equal to two times the number of months of weather-sensitive obligation in the ERS Contract Period.

(ii) The duration of a Weather-Sensitive ERS Load's deployment obligation time for a single event shall be a maximum of three hours.

[NPRR1090: Delete paragraph (3) above upon system implementation and renumber accordingly.]

(4) Unless ERCOT has received a notice of unavailability in a format prescribed by ERCOT, ERCOT shall assume that a contracted ERS Resource is fully available to provide ERS.

(5) QSEs and ERS Resources they represent shall meet the following technical requirements:

(a) Each ERS Resource, including each member of an aggregated ERS Resource, must have an ESI ID or Resource ID (RID) and dedicated metering, as defined by ERCOT. An ERS Resource located outside of a competitive service area may use a unique service identifier in lieu of an ESI ID or RID. ERCOT shall analyze 15-minute interval meter data, adjusted for the deemed actual Distribution Loss Factors (DLFs), for each ERS Resource for purposes of offer analysis, availability and performance measurement. ERS Resources behind a NOIE meter point shall arrange, preferably with the NOIE TDSP, to provide ERCOT with 15-minute interval meter data subject to ERCOT's specifications and approval. ERS Resources behind a Private Use Network's Settlement Meter point shall provide ERCOT 15-minute interval meter data subject to ERCOT's specifications and approval. All generators in an ERS Resource must have TDSP metering capable of measuring energy exported to the ERCOT System and TDSP metering capable of measuring energy imported from the ERCOT System. The QSE must also ensure that interval metering is installed that measures the output of each site in the ERS Generator and that conforms with the requirements described in P.U.C. SUBST. R. 25.142, Submetering for Apartments, Condominiums, and Mobile Home Parks. Time stamps shall conform to the requirements in Section 10.9.2, TSP or DSP Metered Entities. The ERS Resource associated with unique meters in competitive choice areas will be adjusted by the same DLFs as the ESI ID associated with that ERS Resource. The ERS Resource associated with unique meters in NOIE areas will be adjusted based on a NOIE DSP DLF study submitted to ERCOT pursuant to paragraph (6) of Section 13.3, Distribution Losses.

(b) An ERS Resource participating in ERS-10 must be capable of meeting its event performance obligations relevant to its assigned performance evaluation methodology within ten minutes of an ERCOT Dispatch Instruction to its QSE, and must be able to maintain such performance for the entire Sustained Response Period. An ERS Resource participating in ERS-30 must be capable of meeting its event performance obligations relevant to its assigned performance evaluation methodology within 30 minutes of an ERCOT Dispatch Instruction to its QSE, and must be able to maintain such performance for the entire Sustained Response Period.

(c) A QSE must be capable of communicating with its ERS Resources in sufficient time to ensure deployment as described in paragraph (b) above.

(d) QSEs shall communicate to ERCOT, in a method prescribed by ERCOT, material changes in the availability status of their ERS Resources.

(e) An ERS Resource deployed for ERS must be able to return to a condition such that it is capable of meeting its ERS performance requirements within ten hours following a release Dispatch Instruction.

(f) ERS Resources and their QSEs are subject to qualification based on ERCOT's evaluation of their historical meter data and, if applicable, their historic performance in providing other comparable ERCOT services. ERS Resources and their QSEs are subject to testing requirements as described in Section 8.1.3.2, Testing of Emergency Response Service Resources.

(g) ERS Resources are not subject to the modeling, telemetry and COP requirements of other Resources.

(6) The contracted capacity of ERS Resources may not be used to provide Ancillary Services during a contracted ERS Time Period. Nothing herein shall be construed to limit passive (voluntary) Load response, provided the ERS Resource meets its performance and availability requirements, as described in Section 8.1.3.1, Performance Criteria for Emergency Response Service Resources.

(7) QSEs representing ERS Resources must meet the requirements specified in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities.

3.14.3.4 Emergency Response Service Reporting and Market Communications

(1) ERCOT shall review the effectiveness and benefits of ERS every 12 months from the start of the program year and report its findings to TAC no later than April 15 of each calendar year.

(2) Prior to the start of the first ERS Contract Period in an ERS Standard Contract Term, and no later than the end of the third Business Day following the start of any subsequent ERS Contract Period in an ERS Standard Contract Term, ERCOT shall post on the ERCOT website the number of MW procured per ERS Time Period, the number and type of ERS Resources selected, and the projected total cost of ERS for that ERS Contract Period.

(3) ERCOT shall post the following documents to the MIS Certified Area for each of the four ERS service types:

(a) ERS Award Notification;

(b) ERS Resources Submission Form – Approved;

(c) ERS Resource Event Performance Summary;

(d) ERS Resource Availability Summary;

(e) ERS Test Portfolio;

(f) ERS Resource Test Results;

(g) ERS Pre-populated Resource Identification Forms;

(h) ERS Resource Group Assignments;

(i) ERS Resource Submission Form – Error Reports;

(j) ERS Preliminary Baseline Review Results;

(k) ERS QSE Portfolio Availability Summary;

(l) ERS QSE Portfolio Event Performance Summary;

(m) ERS Meter Data Error Report;

(n) ERS QSE-level Payment Details Report; and

(o) ERS Obligation Report for TDSPs.

(4) At least 24 hours before an ERS Standard Contract Term begins, or within 72 hours after the beginning of a new ERS Contract Period within an ERS Standard Contract Term, ERCOT shall post the information below to the MIS Certified Area for each affected TDSP:

(a) A list of ERS Resources and members of aggregated ERS Resources located in the TDSP's service area that will be participating in ERS during the upcoming ERS Standard Contract Term;

(b) The name of the QSE representing each ERS Resource;

(c) The ERS service type provided by each ERS Resource for each ERS Time Period;

(d) All applicable ESI IDs or unique meter identifier associated with each ERS Resource;

(e) Estimate of the ERS MW obligation by station code for TDSPs in competitive areas;

(f) Estimate of the ERS MW obligation by zip code for TDSPs in NOIE areas; and

(g) The date(s) of the interconnection agreement(s) for each generator in any ERS Generator.

(5) TDSPs shall maintain the confidentiality of the information provided pursuant to paragraph (4) above.

(6) ERCOT shall post to the ERCOT website the following information for each ERS offer 60 days after the first day of the ERS Standard Contract Term:

(a) The name of the QSE submitting the offer;

(b) For each ERS Time Period, the price and quantity offered, or if the offer is for self-provided ERS, the quantity offered and an indication that the MW will be self-provided; and

(c) The ERS service type.

[NPRR885, NPRR995, and NPRR1007: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885 or NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

3.14.4 Must-Run Alternative Service

3.14.4.1 Overview and Description of MRAs

(1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.

(2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.

(a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

(b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.

(c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT's acceptance of an offer for a Demand Response MRA on ERCOT's acceptance of an offer for a co-located Other Generation MRA offer.

(d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.

(3) An MRA may be connected at either transmission or distribution voltage.

(4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT's RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.

(5) Each MRA must provide at least five MW of capacity.

(6) Eligible MRA resources may include:

(a) A proposed Generation Resource that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Proposed Generation Resources must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generator Interconnection or Modification.

(ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the MRA Contracted Hours.

(b) Proposed capacity additions to existing Generation Resources, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary Generator interconnection requirements with respect to this additional capacity.

(ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.

(c) A proposed or existing generator registered, or proposed to be registered, with ERCOT as a Settlement Only Generator (SOG) or as Distributed Generation (DG). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA's projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.

(d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads.

(e) A proposed or existing Energy Storage System (ESS) registered, or proposed to be registered, with ERCOT as a Settlement Only Energy Storage System (SOESS).

(7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT's discretion during the MRA Contracted Hours.

(a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA's temporal constraints.

(b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather–Sensitive MRA.

(8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.

(9) ERCOT will periodically validate an MRA's telemetry using 15-minute interval meter data.

(10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service. Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.

(11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, Other Generation MRA, or Demand Response MRA).

(12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.

(13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.

(14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.

(15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.

(16) QSEs must submit the following information for each MRA offer:

(a) The capacity, months and hours offered;

(b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;

(c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;

(d) The MRA Standby Price, represented in dollars per MW per hour;

(e) Required capital expenditure, if any, if the MRA offer is awarded;

(f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;

(g) The ramp period or startup time of the MRA or aggregated MRA;

(h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;

(i) The target availability of the MRA or aggregated MRA; and

(j) Any additional information required by ERCOT within the RFP.

(17) Demand Response MRAs shall not be deployed more than once per Operating Day.

(18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.

(19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource.

[NPRR885: Insert Section 3.14.4.2 below upon system implementation:]

3.14.4.2 Preliminary Review of Prospective Demand Response MRAs

(1) In order to assist QSEs prior to their submission of MRA offers, ERCOT may provide QSEs, upon request, with an analysis of their prospective Demand Response MRA’s consumption patterns.

(2) ERCOT will provide a QSE with the analysis described under this Section only when the QSE makes its request in conformance with submission requirements and deadline set forth in the relevant MRA RFP.

(3) In response to a proper and timely request by a QSE, ERCOT will provide the following information for each prospective Demand Response MRA:

(a) Substation identification for each MRA or MRA Site;

(b) Demand Response MRA baseline options, if the resource qualifies for a default baseline; and

(c) Historical reference Load levels; and

(d) Any known errors or exceptions, such as whether the MRA or any MRA Sites are currently suspended from participation in another service (e.g., ERS), whether any listed MRA or MRA Sites have erroneous ESI IDs, or whether any prospective MRA or MRA Site lacks sufficient historical meter data.

(4) A submission by a QSE of a prospective Demand Response MRA does not bind the QSE to submit an offer for MRA Service.

[NPRR885: Insert Section 3.14.4.3 below upon system implementation:]

3.14.4.3 MRA Substitution

(1) Subject to approval by ERCOT, a QSE may provide a substitution for a contracted MRA. Any substituted MRA is subject to the same obligations as the originally awarded MRA.

(2) ERCOT, at its discretion, may disallow an MRA substitution if it determines that the substitution may cause operational or reliability concerns, does not provide expected reliability benefits equivalent to those under the MRA Agreement, or is inconsistent with Protocols.

(3) Any substitution must cover all MRA Contracted Hours in an Operating Day and may cover one or more Operating Days.

(4) For purposes of payment, for any calendar day during which one or more MRA substitutions was made, the performance of an MRA shall be determined based on the combined performance of the original and substitution MRAs.

[NPRR885: Insert Section 3.14.4.4 below upon system implementation:]

3.14.4.4 Commitment and Dispatch

(1) ERCOT may commit and/or Dispatch an MRA during the term of the MRA Agreement for the purpose of utilizing the MRA's contracted capacity at any time during the contracted hours in the MRA Agreement.

(2) ERCOT may commit an MRA, via VDI, prior to the contracted hours in the MRA Agreement based on the MRA's ramp period or startup time, in order to ensure that the MRA Service is provided during the contracted hours.

(3) In an MRA deployment event or unannounced test, the start time of the Demand response Ramp Period and/or generator startup time will be determined by ERCOT upon review of the time-stamped recording of the VDI. The start time begins when the ERCOT operator confirms the QSE's repeat-back of the instruction.

[NPRR885: Insert Section 3.14.4.5 below upon system implementation:]

3.14.4.5 Standards for Generation Resource MRAs

(1) A Generation Resource MRA shall at all times communicate accurate Resource Status to ERCOT via telemetry as described in Section 6.4.6, Resource Status.

(2) A Generation Resource MRA shall be committed by ERCOT VDI and Dispatched by SCED.

[NPRR885: Insert Sections 3.14.4.6 and 3.14.4.6.1 below upon system implementation:]

3.14.4.6 Standards for Other Generation MRAs and Demand Response MRAs

3.14.4.6.1 MRA Telemetry Requirements

(1) A QSE representing an Other Generation MRA shall at all times communicate an accurate status to ERCOT via telemetry at the MRA level and shall provide at least the following values:

(a) Status (e.g., ON, OUT, etc…);

(b) High Sustained Limit (HSL);

(c) LSL;

(d) Current output level in MW;

(e) Gross Reactive Power in MVAr; and

(f) Net Reactive Power in MVAr.

(2) A Demand Response MRA's QSE shall at all times communicate accurate MRA status to ERCOT via telemetry and shall provide at least the following values:

(a) Net Power Consumption (NPC); and

(b) Low Power Consumption (LPC)

(3) Event performance for Other Generation MRAs that are not Dispatched by SCED shall be evaluated by ERCOT as described in Section 3.14.4.6.5, MRA Event Performance Measurement and Verification.

[NPRR885: Insert Section 3.14.4.6.2 below upon system implementation:]

3.14.4.6.2 Baseline Performance Evaluation Methodology for Demand Response MRAs

(1) A Demand Response MRA must qualify for one or more options described in the document entitled "Default Baseline Methodology" posted on the ERCOT website. The baseline will be used to verify the Demand Response MRA's performance as compared to its contracted capacity during an MRA deployment event.

[NPRR885: Insert Section 3.14.4.6.3 below upon system implementation:]

3.14.4.6.3 MRA Metering and Metering Data

(1) Each Demand Response MRA, or each MRA Site within an aggregated Demand Response MRA, must have an ESI ID and dedicated 15-minute Interval Data Recorder (IDR) metering. A Demand Response MRA, or an MRA Site within an aggregated Demand Response MRA, that is located outside of a competitive service area may use a unique meter ID in lieu of an ESI ID.

(2) Each Other Generation MRA, or each MRA Site within an aggregated Other Generation MRA, must have an ESI ID and, if applicable, a Resource ID and dedicated 15-minute IDR metering. An Other Generation MRA, or an MRA Site within an aggregated Other Generation MRA, that is located outside of a competitive service area may use unique meter IDs in lieu of the ESI ID and Resource ID.

(3) For ESI IDs and Resource IDs situated in either NOIE or competitive choice areas of the ERCOT Region, meter data is stored in the ERCOT systems and will be accessed by ERCOT and used for all performance evaluations.

(4) A QSE representing an MRA or MRA Site in a NOIE service territory is responsible for arranging with the NOIE TDSP to provide ERCOT with interval meter data for the

MRA or MRA Site in a format prescribed by ERCOT on a monthly basis within 35 days following the end of a calendar month.

(5) ERCOT shall use 15-minute interval meter data, adjusted for the deemed actual DLFs, for each Demand Response MRA and each Other Generation MRA for purposes of availability and event performance measurement.

(a) The interval meter data for an MRA or MRA Site located in a competitive choice area will be adjusted by the DLFs used for Settlement for that MRA or MRA Site.

(b) The interval meter data for an MRA or MRA Site associated with a Unique Meter ID in a NOIE area will be adjusted based on a NOIE DSP DLF study submitted to ERCOT pursuant to Section 13.3, Distribution Losses. If no such study has been submitted, the interval meter data will not be adjusted for distribution losses.

[NPRR885: Insert Section 3.14.4.6.4 below upon system implementation:]

3.14.4.6.4 MRA Availability Measurement and Verification

(1) Demand Response MRA and Other Generation MRA availability will be evaluated on a monthly basis.

(2) Within 45 days after the end of each month that a Demand Response MRA or an Other Generation MRA is obligated to be available under the terms of an MRA Agreement, ERCOT shall provide each QSE representing that MRA with a report of the MRAs availability for that month.

(3) For a Demand Response MRA or an Other Generation MRA, ERCOT will treat the MRA as unavailable for any committed intervals for which the meter data is not in ERCOT systems, regardless of the reason.

(4) For a Demand Response MRA, ERCOT will consider the Demand Response MRA to have been available for any 15-minute interval in which the Demand Response MRA was contracted and for which the most current Availability Plan for the Demand Response MRA indicates that the Demand Response MRA is available and for which the effective actual MW Load was greater than 95% of the Demand Response MRA’s effective contracted capacity; otherwise, the Demand Response MRA will be considered unavailable for that 15-minute interval. For purposes of payment under Section 6.6.6.7, MRA Standby Payment, the Demand Response MRA’s Monthly Availability Factor will be the ratio of the number of 15-minute intervals the Demand Response MRA was available during the MRA Contracted Month divided by the total

number of contracted 15-minute intervals in the MRA Contracted Month. For purposes of this paragraph, the following shall apply:

(a) The effective actual MW Load in an interval for an aggregated Demand Response MRA shall be the aggregated sum across all MRA Sites of the product of -1, the MRA Site Shift Factor, and the MRA Site metered MW;

(b) The effective actual MW Load in an interval for a Demand Response MRA that is not an aggregation shall be the product of -1, the MRA Shift Factor, and the metered MW value;

(c) The effective contracted capacity in an interval for an aggregated Demand Response MRA shall be the aggregated sum across all MRA Sites of the product of -1, the MRA Site Shift Factor, and the MRA Site's portion of the contract capacity; and

(d) The effective contracted capacity in an interval for a Demand Response MRA that is not an aggregation shall be the product of -1, the MRA Shift Factor, and the contract capacity.

(5) For an Other Generation MRA, ERCOT will consider the Other Generation MRA to have been available for any 15-minute interval in which the Other Generation MRA was contracted and for which the most current Availability Plan for the Other Generation MRA indicates that the Other Generation MRA is available and for which the Other Generation MRA's export to the ERCOT System was equal to zero; otherwise, the Other Generation MRA will be considered unavailable for that 15-minute interval. For purposes of payment under Section 6.6.6.7, the Other Generation MRA's Monthly Availability Factor will be the ratio of the number of 15-minute intervals the Other Generation MRA was available during the MRA Contracted Month divided by the total number of contracted 15-minute intervals in the MRA Contracted Month.

(6) The following intervals will be excluded in ERCOT's calculations of an MRA's Monthly Availability Factor, for purposes of payment under Section 6.6.6.7:

(a) Any 15-minute interval in which an MRA was deployed during an MRA deployment event or an unannounced ERCOT test;

(b) Any 15-minute intervals on the day of an MRA deployment or an unannounced ERCOT test following the issuance of the ERCOT recall instruction applicable to that MRA; and

(c) Any 15-minute interval in which an MRA or MRA Site was disabled or unverifiable due to events on the TDSP side of the meter affecting the generation, delivery or measurement of electricity to the MRA or MRA Site. QSEs must obtain documentation from the TDSP regarding such events and must provide copies of such documentation to ERCOT for any interval to be excluded from the Monthly Availability Factor calculation.

[NPRR885: Insert Section 3.14.4.6.5 below upon system implementation:]

3.14.4.6.5 MRA Event Performance Measurement and Verification

(1) This section applies to both Demand Response MRAs and Other Generation MRAs. For purposes of this section, the following definitions apply:

(a) "Ramp Period" is the period of time, as set out in the MRA Agreement, by which the MRA agrees to begin delivering its contracted capacity following the ERCOT deployment VDI.

(b) "MRA Deployment Period" is the window of time beginning with the end of the MRA's Ramp Period or the beginning of the MRA Contracted Hours, whichever is later, and ending with ERCOT's VDI to recall the MRA.

(2) No later than 45 days after an event in which one or more Demand Response MRA or Other Generation MRA were tested or deployed, ERCOT shall provide each QSE representing an MRA with a performance report containing the results of ERCOT's evaluation of the event or test for each deployed or tested MRA. The Event Performance Reduction Factor (MRAEPRF) for each MRA shall be the time-weighted average of the MRA's Interval Performance Factors (MRAIPF) which are calculated as set out in paragraph (3) below.

(3) ERCOT shall calculate the MRAIPF for intervals during an unannounced ERCOT test or an MRA deployment as follows:

$$\text{MRAIPF}_{q,\,r,\,i} = \text{Max}(\text{Min}(((\text{Effective Base\_MW}_{i} - \text{Effective Actual\_MW}_{i}) / (\text{IntFrac}_{i} * \text{Effective Contracted\_Capacity\_MW}_{i})),1),0)$$

Where:

$$\text{IntFrac}_{i} = (\text{CEndT}_{i} - \text{CBegT}_{i}) / 15$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$\text{MRAEPRF}_{q,\,r,\,m}$	None	*Must-Run Alternative Event Performance Reduction Factor per QSE for the month*—The Event Performance Reduction Factor of the MRA *r* represented by QSE *q*, for each hour of the month *m*. The event performance reduction factor shall be determined as the time-weighted average of the Interval Performance Factor (MRAIPF).
$\text{MRAIPF}_{q,\,r,\,i}$	None	*Must-Run Alternative Interval Performance Factor per QSE per Resource for the interval*— The interval performance factor of the MRA *r* represented by QSE *q*, for the Settlement Interval *i*.
IntFrac_{i}	None	Interval fraction for that MRA for each Settlement Interval *i* in an MRA deployment period.

Effective Base_MW $_i$	MW	For an aggregated Demand Response MRA, the aggregated sum of the product of -1, the MRA Site Shift Factor, and the MRA Site baseline MW values estimated by ERCOT for all MRA Sites in the MRA for that interval. For a Demand Response MRA that is not an aggregation, the product of -1, the MRA Shift Factor, and the MRA baseline MW value estimated by ERCOT for that interval. For an aggregated Other Generation MRA, the aggregated sum of the product of -1, the MRA Site Shift Factor, and the MRA Site MW injected to the ERCOT System for the Settlement Interval *i*. For an Other Generation MRA that is not an aggregation, the product of -1, the MRA Shift Factor, and the MW injected to the grid by the MRA for that interval.
Effective Actual_MW $_i$	MW	For an aggregated Demand Response MRA, the aggregated sum of the product of -1, the MRA Site Shift Factor and the metered MW values for all MRA Sites in the MRA for the Settlement Interval *i*. For a Demand Response MRA that is not an aggregation, the product of -1, the MRA Shift Factor and the metered MW value for the Settlement Interval *i*. For an Other Generation MRA, zero.
Effective Contracted_Capacity_MW $_i$	MW	For an aggregated MRA, the sum of the product of -1, the MRA Site Shift Factor and the MRA Site portion of the contracted capacity of the MRA for the Settlement Interval *i*.
CBegT $_i$	Minutes	If the MRA deployment period begins during that interval, the time in minutes and fractions of minutes from the beginning of that interval to the beginning of the MRA deployment period, otherwise it is zero.
CEndT $_i$	Minutes	If the MRA deployment period ends during that interval, the time in minutes and fractions of minutes from the beginning of that interval to the end of the MRA deployment period, otherwise it is 15.
i	None	A 15-minute Settlement Interval.
q	none	A QSE.
m	None	The index for a given month within the MRA Contracted Hours.
r	None	An MRA.

(4) For each unannounced ERCOT test or MRA deployment of a Demand Response MRA or Other Generation MRA, ERCOT will calculate an MRA Event Performance Reduction Factor (MRAEPRF) as described in paragraph (2) above for the intervals covered by the test/event. The Event Performance Reduction Factor calculation will begin with the first partial or full interval in the MRA deployment period and will end with the last full interval in the MRA deployment period.

(5) A Demand Response MRA shall be deemed to have met its test/event performance requirements if it is determined by ERCOT to have met its Demand response obligations in the MRA deployment event as measured using the ERCOT-established baseline that ERCOT determines most accurately represents the Demand Response MRA's Demand response contribution.

(6) The MRA deployment period for a Demand Response MRA or Other Generation MRA will end at the time ERCOT issues a release instruction via VDI, or the end of the last MRA Contracted Hour on the day of the deployment, whichever is earlier.

(7) Event Performance Reduction Factors are expressed as a number between 0 and 1, rounded to three decimal places.

(8) A Demand Response MRA or an Other Generation MRA that achieves an Event Performance Reduction Factor of 0.950 or greater for a test/event and an Interval Performance Factor for the first full interval of the test/event of 0.950 or greater will be deemed to have successfully met its deployment obligations for that test/event.

(9) If a Demand Response MRA or an Other Generation MRA fails to achieve an Event Performance Reduction Factor of 0.950 or greater, the Interval Performance Factors for that MRA for that event will be multiplied by an adjustment factor such that the Event Performance Reduction Factor for the test/event will be equal to the square of the original event performance factor.

(10) If a Demand Response MRA has been classified by ERCOT as providing Weather-Sensitive MRA, and if ERCOT determines that the normalized peak Demand reduction value for the Demand Response MRA is greater than 95% of the largest contracted capacity value offered in any MRA Contracted Hour by the QSE for the Demand Response MRA, ERCOT shall not apply the adjustment factors as specified in paragraph (9) above. To determine the normalized peak Demand reduction value, ERCOT shall:

(a) Calculate an average Demand reduction value across the intervals for each test and/or actual deployment event during the MRA contract period. For this purpose the Demand reduction value for an interval shall be calculated as the greater of zero or effective base MW for the interval less the effective actual MW for the interval; and

(b) Model the relationship of the average Demand reduction values determined in paragraph (a) above to actual weather and use the derived normalized peak Demand reduction value as the value that would be realized under normalized peak weather conditions.

(11) For any contracted month in which ERCOT has deployed one or more Demand Response MRAs or Other Generation MRAs more than once for either an unannounced test or an MRA deployment, the Event Performance Reduction Factor (MRAEPRF) as described in paragraph (2) above for the MRA for the contracted month shall be the time-weighted average of the interval performance factor values for all tests/events in the Contracted Month. The interval performance factors used for this calculation shall reflect any squaring applied pursuant to paragraph (9) above.

[NPRR885: Insert Section 3.14.4.6.5.1 below upon system implementation:]

3.14.4.6.5.1 Event Performance Measurement and Verification for Co-Located Demand Response MRAs and Other Generation MRAs

(1) A Demand Response MRA shall be deemed by ERCOT to be co-located with an Other Generation MRA when all of the following conditions are satisfied:

(a) For an aggregated Demand Response MRA and an aggregated Other Generation MRA, each MRA Site in the Demand Response MRA is physically located with an MRA Site in the Other Generation MRA;

(b) For a Demand Response MRA that is not an aggregation and an Other Generation MRA that is not an aggregation, the Demand Response MRA is physically located with the Other Generation MRA;

(c) For a Demand Response MRA that is not an aggregation and an aggregated Other Generation MRA, the Demand Response MRA is physically located with an MRA Site the Other Generation MRA;

(d) The MRA Contracted Hours for the Demand Response MRA are the same as the MRA Contracted Hours for the Other Generation MRA; and

(e) The Demand Response MRA has not been classified by ERCOT as providing Weather-Sensitive MRA.

(2) If a Demand Response MRA has been deemed by ERCOT to be co-located with an Other Generation MRA, the event performance of the two Resources shall be calculated as a combination. For the calculations described in paragraph (2) of Section 3.14.4.6.5, MRA Event Performance Measurement and Verification, the effective base MW of the combination shall be the sum of the values calculated for the Demand Response MRA and Other Generation MRA, the effective actual MW shall be the sum of the values calculated for the Demand Response MRA and Other Generation MRA, and the effective contract capacity MW shall be the sum of the values calculated for the Demand Response MRA and Other Generation MRA.

(3) For the calculations described in paragraph (3) of Section 3.14.4.6.5, the MRAEPRF for the co-located combination shall be calculated as the time-weighted average of the interval performance factors calculated for the combination of the Demand Response MRA and Other Generation MRA. The steps described in paragraphs (4) through (10) of Section 3.14.4.6.5 shall be followed for the combination of the Demand Response MRA and Other Generation MRA, and the MRAEPRF for the Demand Response MRA and Other Generation MRA for the MRA Contracted Month shall be equal to the MRAEPRF calculated for the combination for the MRA Contracted Month.

[NPRR885: Insert Section 3.14.4.7 below upon system implementation:]

3.14.4.7 MRA Testing

(1) ERCOT shall conduct a test of every MRA prior to the initial MRA Contracted Month.

(2) ERCOT may conduct an unannounced test of any MRA at any time during a MRA Contracted Month. Testing for MRAs, other than for Demand Response MRAs classified as providing Weather-Sensitive MRA, will be limited to no more than once per MRA Contracted Month. Testing for Demand Response MRAs classified as Weather-Sensitive MRA will be limited to no more than twice per MRA Contracted Month.

(3) ERCOT will not conduct an unannounced test of an MRA during a calendar month subsequent to an actual MRA deployment event.

(4) A substituted Demand Response MRA or Other Generation MRA will be subject to monthly unannounced testing regardless of tests or events occurring prior to the start date of the substitution.

(5) ERCOT shall limit the duration of MRA deployment periods of any single test to a maximum of one hour.

(6) For the purposes of Section 6.6.6.7, MRA Standby Payment, ERCOT may adjust the testing capacity results for a Generation Resource MRA to reflect conditions beyond the control of the Generation Resource MRA.

[NPRR885: Insert Section 3.14.4.8 below upon system implementation:]

3.14.4.8 MRA Misconduct Events

(1) With respect to MRA Service, a "Misconduct Event" means any MRA Contracted Hour during which the MRA, in a deployment event, is directed to but does not make available to ERCOT the power injection or Demand response in the amount shown in the MRA Availability Plan.

(2) ERCOT will charge a QSE representing an MRA for unexcused Misconduct Events as specified in Section 6.6.6.11, MRA Charge for Unexcused Misconduct.

(3) ERCOT will assess a single charge to the QSE for each Operating Day on which one or more Misconduct Event occurs.

(4) The QSE may be excused by ERCOT from a Misconduct Event charge if ERCOT determines, in its discretion, that the Misconduct Event was not due to intentionally incomplete or inaccurate reporting to ERCOT regarding the availability of the MRA.

(5) ERCOT shall inform the QSE in writing of its determination if a Misconduct Event is deemed unexcused.

[NPRR885: Insert Section 3.14.4.9 below upon system implementation:]

3.14.4.9 MRA Reporting to Transmission and/or Distribution Service Providers (TDSPs)

(1) At least 24 hours before the beginning of an MRA Contracted Month, ERCOT shall provide the report described in paragraph (2) below to each TDSP that has a Demand Response MRA or Other Generation MRA within their service area that is providing MRA Service for the MRA Contracted Month.

(2) The report will include the following information for each MRA and MRA Site within the TDSP's service area:

(a) The name of the QSE representing each MRA or MRA Site;

(b) A list of the Resource IDs, ESI IDs, and Unique Meter IDs for each MRA or MRA Site;

(c) The date of the interconnection agreement for each Resource ID; and

(d) For each Operating Hour, the aggregate contracted capacity for all MRAs and MRA Sites within the TDSP's service area, by station code in competitive areas and by zip code in NOIE areas.

(3) Reports provided under this section are Protected Information under Section 1.3.1.1, Items Considered Protected Information. TDSPs shall maintain the confidentiality of the reports.

3.14.5 Firm Fuel Supply Service

(1) Each Generation Resource providing Firm Fuel Supply Service (FFSS) must meet technical requirements specified in Section 8.1.1, QSE Ancillary Service Performance Standards, and Section 8.1.1.1, Ancillary Service Qualification and Testing.

(2) ERCOT shall issue an RFP by August 1 of each year soliciting bids from QSEs for Generation Resources to provide FFSS. The RFP shall require bids to be submitted on or before September 1 of each year.

(3) QSEs may submit bids individually for one or more Generation Resources to provide FFSS using a bid submission form posted on the ERCOT website. A QSE may not submit a bid for a given Generation Resource unless it is the QSE designated by the Resource Entity associated with that Generation Resource. ERCOT must evaluate bids using criteria identified in an appendix to the RFP. ERCOT will issue FFSS awards for each Generation Resource by September 30 and will post the awards to the MIS Certified Area for each QSE that is awarded an FFSS obligation. The posting will include information such as, but not limited to, the identity of the Resource, the FFSS Standby Fee awarded, the amount of reserved fuel associated with the FFSS award, and MW amount awarded, and the Generation Resource's initial minimum LSL when providing FFSS. The RFP awards shall cover a period beginning November 15 of the year in which the RFP is issued and ending on March 15 of the second calendar year after the year in which the RFP is issued. A QSE may submit a bid for one or more Generation Resources to provide FFSS beginning in the same year the RFP is issued or beginning in a subsequent year covered by the RFP. An FFSS Resource (FFSSR) shall be considered an FFSSR and is required to provide FFSS from November 15 through March 15 for each year of the awarded FFSS obligation period. ERCOT shall ensure FFSSRs are procured and deployed as necessary to maintain ERCOT System reliability during, or in preparation for, a natural gas curtailment or other fuel supply disruption.

(a) On the bid submission form, the QSE shall disclose information including, but not limited to, the amount of reserved fuel offered, the MW available from the capacity offered, and each limitation of the offered Resource that could affect the Resource's ability to provide FFSS.

(b) When a Resource is selected to provide FFSS, the Resource shall complete all applicable testing requirements as specified in Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, and Decertification.

(c) An offer to provide FFSS is an offer to supply an awarded amount of capacity, maintain an awarded amount of fuel, and to designate a specific number of emissions hours for which the awarded FFSSR is obligated to perform in the event that FFSS is deployed. Reserved fuel, emissions hours, and other attributes, in excess of the FFSS awards can be used at the discretion of the QSE as long as the awarded fuel reserves and emissions hours are maintained for the purposes of ERCOT deployment of FFSS.

(4) The QSE for an FFSSR shall ensure that the Resource is prepared and able to come On-Line or remain On-Line in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption.

(a) When ERCOT issues a Watch for winter weather, ERCOT will notify all Market Participants, including all QSEs representing FFSSRs to begin preparation for potential FFSS deployment. Such preparation may include, but is not limited to, circulation of alternate fuel to its facilities, if applicable; heat fuel oil to appropriate temperatures, if applicable; call out additional personnel as necessary, and be ready to receive a Dispatch Instruction to provide FFSS. An FFSSR may begin consuming a minimum amount of alternate fuel to validate it is ready for an FFSS deployment.

(b) In anticipation of or in the event of a natural gas curtailment or other fuel supply disruption to an FFSSR, the QSE shall notify ERCOT as soon as practicable and may request approval to deploy FFSS to generate electricity. ERCOT shall evaluate system conditions and may approve the QSE's request. The QSE shall not deploy the FFSS unless approved by ERCOT. Upon approval to deploy FFSS, ERCOT shall issue an FFSS VDI to the QSE.

(c) In conjunction with a QSE notification under paragraph (b) above, the QSE shall also report to ERCOT any environmental limitations that would impair the ability of the FFSSR to provide FFSS for the required duration of the FFSS award.

(d) ERCOT may issue an FFSS VDI without a request from the QSE, however ERCOT shall not issue an FFSS VDI without evidence of an impending or actual fuel supply disruption affecting the FFSSR.

(e) If the FFSSR is generating at a level above the FFSS MW awarded amount and that level of output cannot be sustained for the required duration of the FFSS award, ERCOT may use a manual High Dispatch Limit (HDL) override to ensure the FFSSR can continue to generate at the FFSS MW award level for the entire FFSS award duration.

(f) The FFSSR shall continuously deploy FFSS to generate electricity until the earlier of (i) the exhaustion of the FFSS service duration as defined in the RFP, (ii) the fuel supply disruption no longer exists, or (iii) ERCOT determines the FFSS deployment is no longer needed. Upon satisfying one of these qualifications, ERCOT shall terminate the VDI and the FFSSR shall not be obligated to continue its FFSS deployment for the remainder of the Watch.

(g) A QSE shall notify ERCOT of the anticipated exhaustion of emissions credits or permit allowances at least six hours before the exhaustion of those credits or allowances. Upon receiving such notification, ERCOT shall modify the VDI so the FFSS deployment is terminated upon exhaustion of those credits or allowances.

(h) Upon deployment or recall of FFSS, ERCOT shall notify all Market Participants that such deployment or recall has been made, including the MW capacity of service deployed or recalled.

(5) During or following the deployment of FFSS, the QSE for an FFSSR may request an approval from ERCOT to restock their fuel reserve to restore their FFSS capability. Following approval from ERCOT, a QSE may restock their FFSS obligation. In the event ERCOT does not receive the request to restock from a QSE representing an FFSSR, ERCOT may instruct QSE to start restocking fuel reserve to restore its FFSS capability.

(6) FFSSRs providing BSS must reserve FFSS capability in addition to the contracted BSS obligation. Any remaining fuel reserve in addition to that required for meeting FFSS and BSS obligations can be used at the QSE's discretion.

(7) If ERCOT issues an FFSS VDI to an FFSSR for the same Operating Hour where a RUC instruction was issued, for Settlement, ERCOT will consider the RUC instruction as cancelled.

(8) ERCOT will provide a report to the TAC or its designated subcommittee within 45 days of any FFSS deployments, including the Resources deployed and the reason for the deployments.

(9) Any QSE that submits a bid or receives an award for a SWGR to provide FFSS, and the Resource Entity that owns or controls that SWGR, shall:

(a) Not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the period of the FFSS obligation; and

(b) Take any further action requested by ERCOT to ensure that ERCOT will be classified as the "Primary Party" for the SWGR under any agreement between ERCOT and another Control Area Operator during the period of the FFSS obligation.

(10) On an annual basis after the FFSS season, ERCOT will provide a report separately for the total amounts from Section 6.6.14.1, Firm Fuel Supply Service Fuel Replacement Costs Recovery, and Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery, to the TAC or its designated subcommittee.

3.15 Voltage Support

(1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it on the Market Information System (MIS) Secure Area. ERCOT, the interconnecting TSP, or that TSP's agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions.

(2) All Generation Resources that are connected to Transmission Facilities (including self-serve generating units) and that have a gross generating unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross generating unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) All Generation Resources (including self-serve generating units) and Energy Storage Resources (ESRs) that are connected to Transmission Facilities and that have a gross

unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

(3) Except as reasonably necessary to ensure reliability or operational efficiency, TSPs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource.

[NPRR989: Replace paragraph (3) above with the following upon system implementation:]

(3) Except as reasonably necessary to ensure reliability or operational efficiency, TSPs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource or ESR.

(4) Each Generation Resource required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the generating unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the generating unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource required to provide VSS is issued a new Voltage Set Point, that Generation Resource shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements;

(e) Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource’s Unit Reactive Limit (URL), which is the generating unit’s dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR's nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP's agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability;

[NPRR989, NPRR1038, and NPRR1026: Replace applicable portions of paragraph (4) above with the following upon system implementation of NPRR989 for NPRR989 and NPRR1038; or upon system implementation for NPRR1026:]

(4) Each Generation Resource and ESR required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource or ESR shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource or an ESR required to provide VSS is issued a new Voltage Set Point, that Generation Resource or ESR shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements;

(e) For Generation Resources, the Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource's Corrected Unit Reactive Limit (CURL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR's nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP's agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability. For ESRs, the Reactive Power capability shall be available at all MW levels, when charging or discharging, and may be met through a combination of the ESR's CURL, and/or dynamic VAr-capable devices. For any ESR that achieved Initial Synchronization before December 16, 2019, the requirement to have Reactive Power capability when charging does not apply if the Resource Entity for the ESR has submitted a notarized attestation to ERCOT stating that, since the date of Initial Synchronization, the ESR has been unable to comply with this requirement without physical or software changes/modifications, and ERCOT has provided written confirmation of the exemption to the Resource Entity. The exemption shall apply only to the extent of the ESR's inability to comply with the requirement when the ESR is charging.

(f) For any Generation Resource or Energy Storage Resource (ESR) that is part of a Self-Limiting Facility, the capabilities described in paragraphs (a) and (b) above shall be determined based on the Self-Limiting Facility's established MW Injection limit and, if applicable, established MW Withdrawal limit.

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

[NPRR989: Replace paragraph (5) above with the following upon system implementation:]

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources and ESRs must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

(6) Except for a Generation Resource subject to Planning Guide Section 5.2.1, Applicability, a Generation Resource that has already been commissioned is not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

[NPRR989: Replace paragraph (6) above with the following upon system implementation:]

(6) Except for a Generation Resource or an ESR subject to Planning Guide Section 5.2.1, Applicability, a Generation Resource or an ESR that has already been commissioned is

not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

(7) Wind-powered Generation Resources (WGRs) that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 ("Existing Non-Exempt WGRs"), must be capable of producing a defined quantity of Reactive Power to maintain a set point in the Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (4) above, except in the circumstances described in paragraph (a) below.

(a) Existing Non-Exempt WGRs whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above must conduct an engineering study using the Summer/Fall 2010 on-peak/off-peak Voltage Profiles, or conduct performance testing to determine their actual Reactive Power capability. Any study or testing results must be accepted by ERCOT. The Reactive Power requirements applicable to these Existing Non-Exempt WGRs will be the greater of: the leading and lagging Reactive Power capabilities established by the Existing Non-Exempt WGR's engineering study or testing results; or Reactive Power proportional to the real power output of the Existing Non-Exempt WGR (this Reactive Power profile is depicted graphically as a triangle) sufficient to provide an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the WGR's set point in the Voltage Profile established by ERCOT, and both measured at the POIB.

(i) Existing Non-Exempt WGRs shall submit the engineering study results or testing results to ERCOT no later than five Business Days after its completion.

(ii) Existing Non-Exempt WGRs shall update any and all Resource Registration data regarding their Reactive Power capability documented by the engineering study results or testing results.

(iii) If the Existing Non-Exempt WGR's engineering study results or testing results indicate that the WGR is not able to provide Reactive Power capability that meets the triangle profile described in paragraph (a) above, then the Existing Non-Exempt WGR will take steps necessary to meet that Reactive Power requirement depicted graphically as a triangle by a date mutually agreed upon by the Existing Non-Exempt WGR and ERCOT. The Existing Non-Exempt WGR may meet the Reactive Power requirement through a combination of the WGR's URL and/or automatically switchable static VAr-capable devices and/or dynamic VAr-capable devices. No later than five Business Days after completion of the steps to meet that Reactive Power requirement, the Existing Non-Exempt WGR will update any and all Resource Registration data regarding its

Reactive Power and provide written notice to ERCOT that it has completed the steps necessary to meet its Reactive Power requirement.

(iv) For purposes of measuring future compliance with Reactive Power requirements for Existing Non-Exempt WGRs, results from performance testing or the Summer/Fall 2010 on-peak/off-peak Voltage Profiles utilized in the Existing Non-Exempt WGR's engineering study shall be the basis for measuring compliance, even if the Voltage Profiles provided to the Existing Non-Exempt WGR are revised for other purposes.

(b) Existing Non-Exempt WGRs whose current design allows them to meet the Reactive Power requirements established in paragraph (4) above (depicted graphically as a rectangle) shall continue to comply with that requirement. ERCOT, with cause, may request that these Existing Non-Exempt WGRs provide further evidence, including an engineering study, or performance testing, to confirm accuracy of Resource Registration data supporting their Reactive Power capability.

(8) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the criteria in the ERCOT Operating Guides.

(9) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the criteria in the Operating Guides.

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple generation units including IRRs shall, at a Generation Entity's option, be treated as a single Generation Resource if the units are connected to the same transmission bus.

[NPRR989: Replace paragraph (10) above with the following upon system implementation:]

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple units including IRRs shall, at a Resource Entity's option, be treated as a single Resource if the units are connected to the same transmission bus.

(11) Generation Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the URL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Generation Resource and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

[NPRR989: Replace paragraph (11) above with the following upon system implementation:]

(11) Resource Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the CURL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Resource Entity and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

(12) A Generation Resource and TSP may enter into an agreement in which the Generation Resource compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

[NPRR989: Replace paragraph (12) above with the following upon system implementation:]

(12) A Resource Entity and TSP may enter into an agreement in which the Generation Resource or ESR compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification.

[NPRR989: Replace paragraph (13) above with the following upon system implementation:]

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource or ESR shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification.

(14) Generation Resources shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

[NPRR989: Replace paragraph (14) above with the following upon system implementation:]

(14) Generation Resources or ESRs shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and/or Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

[NPRR989: Replace paragraph (15) above with the following upon system implementation:]

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

(b) The number of wind turbines out of service and not available for operation.

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and/or Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

[NPRR989: Replace paragraph (16) above with the following upon system implementation:]

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of PV equipment that is not able to communicate and whose status is unknown; and

(b) The capacity of PV equipment that is out of service and not available for operation.

[NPRR1029: Insert paragraph (17) below upon system implementation and renumber accordingly:]

(17) Each DC-Coupled Resource must provide a Real-Time SCADA point that communicates to ERCOT the capacity of the intermittent renewable generation component of the Resource that is available for real power and/or Reactive Power injection into the ERCOT System. Each DC-Coupled Resource must also provide Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of any PV generation equipment that is not able to communicate and whose status is unknown;

(b) The capacity of any PV generation equipment that is out of service and not available for operation;

(c) The number of any wind turbines that are not able to communicate and whose status is unknown; and

(d) The number of any wind turbines out of service and not available for operation.

(17) For the purpose of complying with the Reactive Power requirements under this Section 3.15, Reactive Power losses that occur on privately-owned transmission lines behind the POIB may be compensated by automatically switchable static VAr-capable devices.

3.15.1 ERCOT Responsibilities Related to Voltage Support

(1) ERCOT, in coordination with the TSPs, shall establish, and update as necessary, a Voltage Profile at the POIB for each Generation Resource required to provide VSS to maintain system voltages within established limits.

[NPRR989: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT, in coordination with the TSPs, shall establish, and update as necessary, a Voltage Profile at the POIB for each Generation Resource and ESR required to provide VSS to maintain system voltages within established limits.

(2) ERCOT shall communicate to the Qualified Scheduling Entity (QSE) and TSPs the desired voltage at the POIB by providing Voltage Profiles.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall communicate to the Qualified Scheduling Entity (QSE) and TSPs the desired voltage at the POIB by providing Voltage Profiles.

(3) ERCOT, in coordination with TSPs, shall deploy static Reactive Power Resources as required to continuously maintain dynamic reactive reserves from QSEs, both leading and lagging, adequate to meet ERCOT System requirements.

[NPRR1098: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) ERCOT, in coordination with TSPs, shall deploy static Reactive Power Resources as required to continuously maintain dynamic reactive reserves from QSEs and DCTOs, both leading and lagging, adequate to meet ERCOT System requirements.

(4) For any Market Participant’s failure to meet the Reactive Power voltage control requirements of these Protocols, ERCOT shall notify the Market Participant in writing of such failure and, upon a request from the Market Participant, explain whether and why the failure must be corrected.

(5) ERCOT shall notify all affected TSPs of any alternative requirements it approves.

(6) Annually, ERCOT shall review Distribution Service Provider (DSP) power factors using the actual summer Load and power factor information included in the annual Load data request to assess whether DSPs comply with the requirements of this subsection. At times selected by ERCOT, ERCOT shall require manual power factor measurement at substations and points of interconnection for Load that do not have power factor metering. ERCOT shall try to provide DSPs sufficient notice to perform the manual measurements. ERCOT may not request more than four measurements per calendar year for each DSP substation or points of interconnection for Load where power factor measurements are not available.

(7) If actual conditions indicate probable non-compliance of TSPs and DSPs with the requirements to provide voltage support, ERCOT shall require power factor measurements at the time of its choice while providing sufficient notice to perform the measurements.

(8) ERCOT shall investigate claims of TSP and DSP alleged non-compliance with Voltage Support requirements. The ERCOT investigator shall advise ERCOT and TSP planning and operating staffs of the results of such investigations.

3.15.2 DSP Responsibilities Related to Voltage Support

(1) Each DSP and Resource Entity within a Private Use Network shall meet the requirements specified in this subsection, or at their option, may meet alternative requirements specifically approved by ERCOT. Such alternative requirements may include requirements for aggregated groups of Facilities.

(a) Sufficient static Reactive Power capability shall be installed by a DSP or a Resource Entity within a Private Use Network not subject to a DSP tariff in substations and on the distribution voltage system to maintain at least a 0.97 lagging power factor for the maximum net active power measured in aggregate on the distribution voltage system. In those cases where a Private Use Network's power factor is established and governed by a DSP tariff, a Resource Entity within a Private Use Network shall ensure that the Private Use Network meets the requirements as defined and measured in the applicable tariff.

(b) DSP substations whose annual peak Load has exceeded ten MW shall have and maintain Watt/VAr metering sufficient to monitor compliance; otherwise, DSPs are not required to install additional metering to determine compliance.

(c) All DSPs shall report any changes in their estimated net impact on ERCOT as part of the annual Load data assessment.

(d) As part of the annual Load data assessment, all Resource Entities owning Generation Resources shall provide an annual estimate of the highest potential affiliated MW and MVAr Load (including any Load netted with the generation output) and the highest potential MW and MVAr generation that could be experienced at the POIB, based on the current configuration (and the projected configuration if the configuration is going to change during the year) of the Generation Resource and any affiliated Loads.

3.15.3 Generation Resource Requirements Related to Voltage Support

(1) Generation Resources required to provide VSS shall have and maintain Reactive Power capability at least equal to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides.

(2) Generation Resources providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

(3) Generation Resources providing VSS must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing, and the performance standards specified in Section 8.1.1, QSE Ancillary Service Performance Standards.

(4) Each Generation Resource providing VSS shall operate with the unit's Automatic Voltage Regulator (AVR) in the automatic voltage control mode unless specifically directed to operate in manual mode by ERCOT, or when the unit is telemetering its

Resource Status as STARTUP, SHUTDOWN, or ONTEST, or the QSE determines a need to operate in manual mode due to an undue threat to safety, undue risk of bodily harm, or undue damage to equipment at the generating plant.

(5) Each Generation Resource providing VSS shall maintain the Voltage Set Point established by ERCOT, the interconnecting TSP, or the TSP's agent, subject to the Generation Resource's operating characteristic limits, voltage limits, and within tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements.

(6) The reactive capability required must be maintained at all times that the Generation Resource is On-Line.

(7) Each QSE shall send to ERCOT, via telemetry, the AVR and Power System Stabilizer (PSS) status for each of its Generation Resources providing VSS. For AVRs, an "On" status will indicate the AVR is on and set to regulate the Resource's terminal voltage in the voltage control mode, and an "Off" status will indicate the AVR is off or in a manual mode. For PSS, an "On" status will indicate the service is enabled and ready for service, and an "Off" status will indicate it is off or out of service. Each QSE shall monitor the status of its Generation Resources' regulators and stabilizers, and shall report status changes to ERCOT.

(8) Each Resource Entity shall provide information related to the tuning parameters, local or inter-area, of any PSS installed at a Generation Resource.

[NPRR989 and NPRR1026: Replace applicable portions of Section 3.15.3 above with the following upon system implementation:]

3.15.3 Generation Resource and Energy Storage Resource Requirements Related to Voltage Support

(1) Generation Resources and ESRs required to provide VSS shall have and maintain Reactive Power capability at least equal to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides.

(2) Generation Resources and ESRs providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

(3) Generation Resources and ESRs providing VSS must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing, and the performance standards specified in Section 8.1.1, QSE Ancillary Service Performance Standards.

(4) Each Generation Resource and ESR providing VSS shall operate with the unit's Automatic Voltage Regulator (AVR) in the automatic voltage control mode unless specifically directed to operate in manual mode by ERCOT, or when the unit is telemetering its Resource Status as STARTUP, SHUTDOWN, or ONTEST, or the QSE

determines a need to operate in manual mode due to an undue threat to safety, undue risk of bodily harm, or undue damage to equipment at the generating plant.

(5) Each Generation Resource and ESR providing VSS shall maintain the Voltage Set Point established by ERCOT, the interconnecting TSP, or the TSP's agent, subject to the Generation Resource's or ESR's operating characteristic limits, voltage limits, and within tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements.

(6) The reactive capability required must be maintained at all times that the Generation Resource or ESR is On-Line.

(7) Each QSE shall send to ERCOT, via telemetry, the AVR and Power System Stabilizer (PSS) status for each of its Generation Resources providing VSS. Each QSE shall send to ERCOT via telemetry the AVR status for each of its ESRs providing VSS. For AVRs, an "On" status will indicate the AVR is on and set to regulate the Resource's terminal voltage in the voltage control mode, and an "Off" status will indicate the AVR is off or in a manual mode. For PSS, an "On" status will indicate the service is enabled and ready for service, and an "Off" status will indicate it is off or out of service. Each QSE shall monitor the status of its Generation Resources' and ESRs' regulators and stabilizers, and shall report status changes to ERCOT.

(8) Each Resource Entity shall provide information related to the tuning parameters, local or inter-area, of any PSS installed at a Generation Resource.

(9) If any individual Resource within a Self-Limiting Facility is incapable of meeting its Reactive Power requirement at the POI, the QSE must bring On-Line additional Resource(s) within the Self-Limiting Facility to provide VSS as specified in paragraph (4) of Section 3.15, Voltage Support, while respecting the limit on MW Injection.

[NPRR1098: Insert Section 3.15.4 below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

3.15.4 Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support

(1) The following Direct Current Ties (DC Ties) are subject to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides:

(a) Any DC Tie with an initial energization date after January 1, 2021.

(b) Any DC Tie that is modified by increasing the physical capacity of the DC Tie by 20 MW or more or by changing the power converter associated with the DC Tie, unless the replacement is in-kind.

(2) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure that the DC Tie Facility has the following Reactive Power capabilities:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the DC Tie's physical capacity at any voltage from 0.95 per unit to 1.04 per unit, as measured at the Point of Interconnection Bus (POIB);

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less determined at the DC Tie's physical capacity at any voltage from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) Reactive Power capability shall be available at all MW levels, whether injecting or withdrawing power, and may be met through a combination of the DC Tie's dynamic leading and lagging operating capability and/or dynamic VAr-capable devices.

(3) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above must conduct an engineering study demonstrating the ability of the DC Tie Facility to meet the Reactive Power requirements in paragraph (2) above. Any study results must be accepted by ERCOT prior to the initial energization date of the DC Tie.

(4) ERCOT may, with notice, require performance testing to demonstrate a DC Tie Facility's ability to meet the Reactive Power requirements in paragraph (2) above.

(5) Each Direct Current Tie Operator (DCTO) operating a DC Tie Facility meeting the applicability requirements of paragraph (1) above shall comply with any instruction from its designated Transmission Operator (TO) with respect to the DC Tie's reactive power capability, including any instruction to maintain a target voltage at the POIB, subject to the DC Tie's operating characteristic limits and voltage limits, and within the tolerances identified in paragraph (2) of Nodal Operating Guide Section 2.7.3.6, DCTO Responsibilities and DC Tie Requirements, and subject to any superseding Dispatch Instruction from ERCOT.

(6) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall implement a control system to control all devices at a DC Tie Facility needed to meet the Reactive Power requirements in paragraph (2) above.

(a) The control system shall be operated in automatic voltage control mode unless ERCOT directs the DCTO to operate the system in manual mode.

(b) The DCTO shall provide to its designated TO, via telemetry, the status of the control system. An "On" status will indicate that the control system is on and set to regulate the voltage at the DC Tie's POIB in automatic voltage control mode, and an "Off" status will indicate that the control system is off or in manual mode.

3.16 Standards for Determining Ancillary Service Quantities

(1) ERCOT shall comply with the requirements for determining Ancillary Service quantities as specified in these Protocols and the ERCOT Operating Guides.

(2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the quantity requirements for each Ancillary Service needed for reliability, including:

[NPRR863: Insert item (a) below upon system implementation and renumber accordingly:]

(a) The percentage or MW limit of ERCOT Contingency Reserve Service (ECRS) allowed from Load Resources providing ECRS;

(a) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR);

(b) The maximum amount (MW) of Regulation Up Service (Reg-Up) that can be provided by Resources providing Fast Responding Regulation Up Service (FRRS-Up); and

(c) The maximum amount (MW) of Regulation Down Service (Reg-Down) that can be provided by Resources providing Fast Responding Regulation Down Service (FRRS-Down).

[NPRR1007: Delete items (b) and (c) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(d) The minimum capacity required from Resources providing RRS using Primary Frequency Response shall not be less than 1,150 MW.

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from SCED dispatchable Resources to provide Non-Spin, the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, the maximum amount of RRS that can be provided by Resources capable of FFR, and the maximum amount of Reg-Up and Reg-Down that can be provided by Resources providing FRRS-Up and FRRS-Down.

[NPRR1007: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from SCED dispatchable Resources to provide Non-Spin, the minimum capacity required from Resources providing Primary Frequency Response to provide RRS and the maximum amount of RRS that can be provided by Resources capable of FFR.

(4) If ERCOT determines a need for additional Ancillary Service Resources under these Protocols or the ERCOT Operating Guides, after an Ancillary Service Plan for a specified day has been posted, ERCOT shall inform the market by posting notice on the ERCOT website, of ERCOT’s intent to procure additional Ancillary Service Resources under Section 6.4.9.2, Supplemental Ancillary Services Market. ERCOT shall post the reliability reason for the increase in service requirements.

[NPRR1007: Delete paragraph (4) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(5) Monthly, ERCOT shall determine and post on the Market Information System (MIS) Secure Area a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS, provided that RRS from Load Resources on high-set under-frequency relays and Resources providing FFR shall be limited to 60% of the total ERCOT RRS requirement. ERCOT may increase the minimum capacity required from Resources providing RRS using Primary Frequency Response if it believes that the current posted quantity will have a negative impact on reliability or if it would require additional Regulation Service to be deployed.

(6) The amount of RRS that a Qualified Scheduling Entity (QSE) can self-arrange using a Load Resource excluding Controllable Load Resources and Resources providing FFR is limited to its Load Ratio Share (LRS) of the capacity allowed to be provided by Resources not providing RRS using Primary Frequency Response established in paragraph (5) above, provided that RRS from these Resources shall be limited to 60% of the total ERCOT RRS requirement.

(7) However, a QSE may offer more RRS from Load Resources and Resources capable of providing FFR above the percentage limit established by ERCOT for sale of RRS to other Market Participants. The total amount of RRS Service using the Load Resource (excluding Controllable Load Resources) or Resources providing FFR procured by ERCOT is also limited to the capacity established in paragraph (5) above, up to the lesser of the 60% limit or the limit established by ERCOT in paragraph (5) above.

[NPRR863: Replace paragraph (7) above with the following upon system implementation:]

(7) However, a QSE may offer more of the Load Resource above the percentage limit established by ERCOT for sale of RRS to other Market Participants. The total amount of RRS using the Load Resource procured by ERCOT is also limited to the capacity established in paragraph (5) above, up to the lesser of the 60% limit or the limit established by ERCOT in paragraph (5) above.

[NPRR863: Insert paragraphs (8)-(10) below upon system implementation and renumber accordingly:]

(8) Monthly, ERCOT shall determine and post on the MIS Secure Area a minimum capacity required from Resources providing ECRS. The amount of Load Resources excluding Controllable Load Resources that may or may not be on high-set under-frequency relays providing ECRS is limited to 50% of the total ERCOT ECRS requirement.

(9) The amount of ECRS that a QSE can self-arrange using a Load Resource excluding Controllable Load Resources is limited to the lower of:

(a) 50% of its ECRS Ancillary Service Obligation; or

(b) A reduced percentage of its ECRS Ancillary Service Obligation based on the limit established by ERCOT in paragraph (8) above.

(10) A QSE may offer more of the Load Resource above the percentage limit established by ERCOT for sale of ECRS to other Market Participants. The total amount of ECRS using the Load Resource excluding Controllable Load Resources procured by ERCOT is also limited to the lesser of the 50% limit or the limit established by ERCOT in paragraph (9) above.

(8) The maximum MW amount of capacity from Resources providing FRRS-Up is limited to 65 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(9) The maximum MW amount of capacity from Resources providing FRRS-Down is limited to 35 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(10) Resources can only provide FRRS-Up or FRRS-Down if awarded Regulation Service in the Day-Ahead Market (DAM) for that particular Resource, up to the awarded quantity.

[NPRR1007: Delete paragraphs (8)-(10) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

3.17 Ancillary Service Capacity Products

3.17.1 Regulation Service

(1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. Fast Responding Regulation Up Service (FRRS-Up) is a subset of Reg-Up Service in which the participating Resource provides Reg-Up capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal. The LFC signal for FRRS-Up is separate from the LFC signal for other Reg-Up.

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal.

(2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. Fast Responding Regulation Down Service (FRRS-Down) is a subset of Reg-Down Service in which a participating Resource

provides Reg-Down capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Down by an LFC signal. The LFC signal for FRRS-Down is separate from the LFC signal for other Reg-Down.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. ERCOT dispatches Reg-Down by an LFC signal.

3.17.2 Responsive Reserve Service

(1) Responsive Reserve (RRS) is a service used to restore or maintain the frequency of the ERCOT System:

(a) In response to, or to prevent, significant frequency deviations;

(b) As backup Regulation Service; and

(c) By providing energy during an Energy Emergency Alert (EEA).

(2) RRS may be provided through one or more of the following means:

(a) By using frequency-dependent response from On-Line Resources as prescribed in the Operating Guides to help restore the frequency within the first few seconds of an event that causes a significant frequency deviation in the ERCOT System; and

(b) Either manually or by using a four-second signal to provide energy on deployment by ERCOT.

(3) RRS may be used to provide energy during the implementation of an EEA. Under the EEA, RRS provides generation capacity, capacity from Controllable Load Resources or interruptible Load available for deployment on ten minutes' notice.

(4) RRS may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Load Resources controlled by high-set, under-frequency relays;

(c) Controllable Load Resources; and

(d) Hydro RRS as defined in the Operating Guides.

[NPRR863: Replace Section 3.17.2 above with the following upon system implementation:]

3.17.2 Responsive Reserve Service

(1) Responsive Reserve (RRS) is a service used to restore or maintain the frequency of the ERCOT System in response to a significant frequency deviation.

(2) RRS is automatically self-deployed by Resources in a manner that results in real power increases or decreases.

(3) RRS may be provided by:

(a) On-Line Generation Resource capable of providing Primary Frequency Response with the capacity excluding Non-Frequency Responsive Capacity (NFRC);

(b) Resources capable of providing Fast Frequency Response (FFR) and sustaining their response for up to 15 minutes;

(c) Load Resources controlled by high-set under-frequency relays; and

(d) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides.

3.17.3 Non-Spinning Reserve Service

(1) Non-Spinning Reserve (Non-Spin) is provided by using:

(a) Generation Resources, whether On-Line or Off-Line, capable of:

(i) Being synchronized and ramped to a specified output level within 30 minutes; and

(ii) Running at a specified output level for at least four consecutive hours;

(b) Controllable Load Resources qualified for Dispatch by Security-Constrained Economic Dispatch (SCED) and capable of:

(i) Ramping to an ERCOT-instructed consumption level within 30 minutes; and

(ii) Consuming at the ERCOT-instructed level for at least four consecutive hours; or

(c) Load Resources that are not Controllable Load Resources and are qualified for deployment by the operator using the Ancillary Service Deployment Manager and capable of:

(i) Reducing consumption based on an ERCOT Extensible Markup Language (XML) instruction within 30 minutes; and

(ii) Maintaining that deployment until recalled.

(2) The Non-Spin may be deployed by ERCOT to increase available reserves in Real-Time Operations.

[NPRR863 and NPRR1096: Insert applicable portions of Section 3.17.4 below upon system implementation:]

3.17.4 ERCOT Contingency Reserve Service

(1) ERCOT Contingency Reserve Service (ECRS) is a service that is provided using capacity that can be sustained at a specified level for two consecutive hours and is used to restore or maintain the frequency of the ERCOT System:

(a) In response to significant depletion of RRS;

(b) As backup Regulation Service; and

(c) By providing energy to avoid getting into or during an Energy Emergency Alert (EEA).

(2) ECRS may be provided through one or more of the following means:

(a) From On-Line or Off-Line Resources as prescribed in the Operating Guides following a significant frequency deviation in the ERCOT System; and

(b) Either manually or by using a four-second signal to provide energy on deployment by ERCOT.

(3) ECRS may be used to provide energy prior to or during the implementation of an EEA. ECRS provides Resource capacity, or capacity from interruptible Load available for deployment on ten minutes' notice.

(4) ECRS may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Quick Start Generation Resources (QSGRs);

(c) Load Resources that may or may not be controlled by high-set, under-frequency relays;

(d) Controllable Load Resources; and

(e) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides.

3.18 Resource Limits in Providing Ancillary Service

(1) For both Generation Resources and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific designation of capacity to provide Responsive Reserve (RRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), and Non-Spinning Reserve (Non-Spin).

[NPRR863 and NPRR1007: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

(1) For both Generation Resources and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific awards for Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), and Non-Spinning Reserve (Non-Spin).

(2) For Non-Spin, the amount of Non-Spin provided must be less than or equal to the HSL for Off-Line Generation Resources.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) For Non-Spin, the amount of Non-Spin awarded must be less than or equal to the HSL for Off-Line Generation Resources.

(3) For RRS:

(a) The full amount of RRS awarded to or self-arranged from an On-Line Generation Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource subject to verified droop performance. The default value for any newly qualified Generation Resource shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;

(b) Generation Resources operating in the synchronous condenser fast-response mode may provide RRS up to the Generation Resource's proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz. Once deployed, a Resource telemetering a Resource Status of ONRR shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled by ERCOT after frequency recovers above 59.98 Hz, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility;

(c) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and

(d) The amount of RRS provided from a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz. A Resource providing RRS as FFR that is deployed shall not recall its capacity until system frequency is greater than 59.98 Hz. Once deployed, a Resource telemetering a Resource Status of ONFFRRRS or ONFFRRRSL shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility. Once recalled, a Resource providing RRS as FFR must restore its full RRS Ancillary Service Resource Responsibility within 15 minutes after cessation of deployment or as otherwise directed by ERCOT.

[NPRR1007: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) For RRS:

(a) The full amount of RRS that can be provided by an On-Line Generation Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource subject to verified droop performance. The default value for any newly qualified Generation Resource shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;

(b) Generation Resources operating in the synchronous condenser fast-response mode may be awarded RRS up to the Generation Resource's proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz;

(c) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and

(d) The amount of RRS awarded to a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz.

[NPRR863 and NPRR1007: Insert applicable portions of paragraph (4) below upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

(4) For ECRS:

(a) The full amount of ECRS that can be awarded to an On-Line Generation Resource must be less than or equal to ten times the Emergency Ramp Rate;

(b) The full amount of ECRS that can be awarded to a Quick Start Generation Resource (QSGR) must be less than or equal to its proven ten-minute capability as demonstrated pursuant to paragraph (16) of Section 8.1.1.2, General Capacity Testing Requirements;

(c) Generation Resources operating in the synchronous condenser fast-response mode may be awarded ECRS up to the Generation Resource's proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz; and

(d) For any Load Resources controlled by under-frequency relay and awarded ECRS, the initiation setting of the automatic under-frequency relay setting shall not be lower than 59.70 Hz. To provide ECRS, Load Resources are not required to be controlled by under-frequency relays.

3.19 Constraint Competitiveness Tests

3.19.1 Constraint Competitiveness Test Definitions

(1) The Constraint Competitiveness Test (CCT) checks the competitiveness of a constraint by evaluating each Market Participant's ability to exercise market power by physical or economic withholding. The CCT for a constrained Transmission Element evaluates

whether there is sufficient competition to resolve the constraint on the import side by calculating the Element Competitiveness Index (ECI) on the import side of the constraint and by determining whether a single Entity is needed to resolve the constraint.

(2) The competitiveness of a constraint is tested both on a long-term basis and before each Security-Constrained Economic Dispatch (SCED) execution.

(3) The "Available Capacity for a Resource" is defined as follows:

(a) For Generation Resources, including Switchable Generation Resources (SWGRs), but excluding Intermittent Renewable Resources (IRRs):

(i) Long-Term CCT - the Seasonal net max sustainable rating, as registered with ERCOT.

(ii) SCED CCT - the telemetered High Sustained Limit (HSL) for Resources with telemetered Resource Status as specified in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria, and zero for all other Resources.

(b) For IRRs:

(i) Long-Term CCT - the Seasonal net max sustainable rating, as registered with ERCOT, on the export side and zero MW on the import side.

(ii) SCED CCT - the telemetered HSL for Resources with telemetered Resource Status as specified in paragraph (5)(b)(i) of Section 3.9.1 and zero for all other Resources.

(c) For the Direct Current Tie (DC Tie) lines, the full import capability on the export side and zero MW on the import side for all CCTs.

(4) "Managed Capacity for an Entity" is a Resource for which a Decision Making Entity (DME) has control over how the Resource is offered or scheduled (e.g., Output Schedules), in accordance with subsection (d) of P.U.C. SUBST. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas.

(5) Shift Factors of all Electrical Buses are computed relative to the distributed load reference Bus.

(a) For voltage, stability, and thermal-limited constraints, as well as interfaces represented by thermal limits, the Shift Factors should be computed with no other contingencies removed from the electrical network.

(b) For contingency-limited constraints, the Shift Factors used should be computed with the contingencies removed from the electrical network.

(6) As part of the Long-Term and SCED CCT processes described below, there are several thresholds used in determining the competitive designation of a constraint and the Resources for which mitigation will be applied in SCED Step 2, as described in Section 6.5.7.3, Security Constrained Economic Dispatch. These thresholds are defined as follows:

Threshold	Definition	Value
SFP1	Minimum Shift Factor threshold for determining which Managed Capacity for an Entity to include in the ECI calculation	2%
ECIT1	Maximum competitive threshold for ECI on the import side of a constraint for the Long-Term CCT process	2000
SFP2	Minimum Shift Factor threshold for a constraint to be eligible to be a Competitive Constraint as part of the Long-Term CCT process	2%
ECIT2	Maximum competitive threshold for ECI on the import side of a constraint for the SCED CCT process	2300
SFP3	Minimum Shift Factor threshold for a constraint to be eligible to be a Competitive Constraint as part of the SCED CCT process	2%
DMEECP	Threshold for the ECI Effective Capacity for a DME to determine if their Managed Capacity for an Entity is eligible to be mitigated as part of SCED Step 2	10%
SFP4	Minimum Shift Factor threshold below which a Resource will not have mitigation applied in SCED Step 2	2%

3.19.2 Element Competitiveness Index Calculation

(1) To compute the ECI on the import side, first determine the "ECI Effective Capacity" available to resolve the constraint. The ECI Effective Capacity that each Entity contributes to resolve the constraint on the import side is determined by taking, for each Managed Capacity for an Entity having negative Shift Factors with absolute values greater than the minimum of one-third of the highest absolute value of any Resource Shift Factor with a negative value and SFP1, the sum of the products of (a) the Available Capacity for a Resource and (b) the square of the Shift Factor of that Resource to the constraint.

(2) ERCOT will determine the ECI on the import of the constraint, as follows:

(a) Determine the total ECI Effective Capacity by each DME on the import side.

(b) Determine the percentage of ECI Effective Capacity by each DME on the import side by taking each DME's ECI Effective Capacity and dividing by the total ECI Effective Capacity on the import side.

(c) The ECI on the import side is equal to the sum of the squares of the percentages of ECI Effective Capacity for each DME on the import side.

3.19.3 Long-Term Constraint Competitiveness Test

(1) The Long-Term CCT process is executed once a year and provides a projection of Competitive Constraints for the month with the highest forecasted Demand in the following year.

(2) The Long-Term CCT performs analysis on a selected set of constraints.

(3) A constraint is classified as a Competitive Constraint for the monthly case if it meets all of the following conditions:

(a) The ECI is less than ECIT1 on the import side of the constraint;

(b) The constraint can be resolved by eliminating all Available Capacity for a Resource on the import side, except nuclear capacity and minimum-energy amounts of coal and lignite capacity, that is Managed Capacity for a DME during peak Load conditions; and

(c) There are negative Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that have an absolute value greater than or equal to SFP2.

(4) Any constraint that is analyzed and does not meet the conditions in paragraph (3) above will be designated as a Non-Competitive Constraint for the monthly case.

(5) ERCOT shall update and post the list of Competitive Constraints identified by the Long-Term CCT on the MIS Secure Area. The list of Competitive Constraints shall be posted at least 30 days prior to the first of the year.

3.19.4 Security-Constrained Economic Dispatch Constraint Competitiveness Test

(1) The SCED CCT uses current system conditions to evaluate the competitiveness of a constraint.

(2) Before each SCED execution, CCT is performed for all active constraints in SCED. The SCED CCT shall classify a constraint as competitive for the current SCED execution if the constraint meets all of the following conditions:

(a) The ECI is less than ECIT2 on the import side;

(b) The constraint can be resolved by eliminating all Available Capacity for a Resource on the import side, except nuclear capacity and minimum-energy amounts of coal and lignite capacity, that is Managed Capacity for a DME. If the constraint cannot be resolved, then the DME will be marked as the pivotal player for resolving the constraint;

(c) There are negative Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that have an absolute value greater than or equal to SFP3; and

(d) The constraint was not designated as non-competitive by a previous SCED CCT execution within the current Operating Hour.

(3) Any constraint that is analyzed and is not designated as a Competitive Constraint under the conditions outlined in paragraph (2) above shall be designated as a Non-Competitive Constraint by the SCED CCT.

(4) A constraint that is determined to be a Non-Competitive Constraint by the SCED CCT within an Operating Hour will not be re-evaluated for its competitiveness status for the remainder of that Operating Hour. However, the SCED CCT will reevaluate the percentage of the ECI Effective Capacity on the import side for each DME and whether the DME is a pivotal player for the constraint. SCED will re-evaluate the competitiveness of the Non-Competitive Constraint starting with the first SCED interval of the next Operating Hour if the constraint remains active in SCED.

(5) The Independent Market Monitor (IMM) may designate any constraint as a Competitive Constraint or a Non-Competitive Constraint. ERCOT shall provide notice describing any such designation by the IMM. The notice shall include an effective date, justification for the constraint designation by the IMM and the duration for which the IMM designation will be applied. Any such designation from the IMM shall override the competitiveness status determined by the SCED CCT for the dates for which the IMM override is effective.

(6) Each hour, ERCOT shall post on the ERCOT website whether each binding constraint was designated as a Competitive Constraint or as a Non-Competitive Constraint for each of the SCED executions during the previous Operating Hour.

(7) Mitigation will be applied to a Resource in the SCED Step 2, as described in Section 6.5.7.3, Security Constrained Economic Dispatch, when all of the following conditions are met:

(a) A constraint has been determined to be a Non-Competitive Constraint by either the SCED CCT or the IMM;

(b) The DME for the Resource is either identified as a pivotal player for the constraint as described in paragraph (4) above or has a percentage of ECI Effective Capacity on the import side for the constraint greater than DMEECP; and

(c) The Resource has a Shift Factor on the import side of the constraint with an absolute value greater than SFP4;

(8) Once mitigation has been applied to a Resource for a SCED interval, it shall remain applied for the remainder of the Operating Hour regardless of the conditions listed in paragraph (7) above.

3.20 Identification of Chronic Congestion

(1) A constraint that has been binding in Real-Time on three or more Operating Days within a calendar month shall be considered to be experiencing chronic congestion.

3.20.1 Evaluation of Chronic Congestion

(1) ERCOT shall evaluate chronic congestion monthly and shall report the results of its evaluation to the appropriate Technical Advisory Committee (TAC) subcommittee(s). The report must identify the constraint(s) causing the chronic congestion.

3.20.2 Topology and Model Verification

(1) For constraints identified in the report required by Section 3.20.1, Evaluation of Chronic Congestion, ERCOT shall notify the appropriate Transmission Service Provider(s) (TSP(s)) or Resource Entity. The TSP or Resource Entity must verify that the data in the Network Operations Model and Updated Network Model is accurate, including the Ratings of the Transmission Facility causing the binding transmission constraint.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) For constraints identified in the report required by Section 3.20.1, Evaluation of Chronic Congestion, ERCOT shall notify the appropriate Transmission Service Provider(s) (TSP(s)), Direct Current Tie Operator (DCTO), or Resource Entity. The TSP, DCTO, or Resource Entity must verify that the data in the Network Operations Model and Updated Network Model is accurate, including the Ratings of the Transmission Facility causing the binding transmission constraint.

(2) If ERCOT determines that the Network Operations Model, the Updated Network Model, or the configuration of the Transmission Facility may be inaccurate, ERCOT shall coordinate with the owner of the Transmission Facility to determine if the Ratings should be updated, as provided by paragraph (3) of Section 3.10, Network Operations Modeling and Telemetry.

3.21 Submission of Declarations of Natural Gas Pipeline Coordination

(1) As part of its submission to ERCOT in connection with subsection (c)(3)(B) of P.U.C. SUBST. R. 25.55, Weather Emergency Preparedness, each Resource Entity representing one or more Generation Resources subject to P.U.C. SUBST. R. 25.55 that uses natural gas as its primary fuel shall submit to ERCOT the declaration in Section 22, Attachment K, Declaration of Natural Gas Pipeline Coordination, stating that the Resource Entity or its Qualified Scheduling Entity (QSE) made a documented effort to communicate with the operator of each natural gas pipeline directly connected to its Generation Resource to coordinate regarding potential impacts to the Generation Resource's availability during the summer Peak Load Season of that year.

(2) If a Resource Entity or its QSE knows an activity or condition related to a natural gas pipeline directly connected to its Generation Resource will cause the Generation Resource's unavailability, in whole or in part, the QSE shall, as soon as practicable, report that Outage or derate in the ERCOT Outage Scheduler in accordance with Section 3.1, Outage Coordination. An Outage or derate reported in the ERCOT Outage Scheduler need not be disclosed in the declaration contained in Section 22, Attachment K, nor reported under paragraph (4) below.

(3) If, before a Resource Entity submits the declaration contained in Section 22, Attachment K, the Resource Entity or its QSE is notified by an operator of a natural gas pipeline directly connected to its Generation Resource of an activity or condition (e.g. maintenance, inspection, malfunction, or third-party damage) that may limit or impede normal deliveries but is uncertain whether the activity or condition during the upcoming summer Peak Load Season will cause the Generation Resource to take an Outage or derate, the Resource Entity shall disclose the natural gas pipeline activity or condition in the declaration contained in Section 22, Attachment K, if the activity or condition materially increases the risk of Generation Resource unavailability during the summer Peak Load Season. The Resource Entity shall use its reasonable judgment to determine whether there is a material increase in the risk of unavailability.

(4) If, after submitting the declaration contained in Section 22, Attachment K, any previously disclosed information changes or a Resource Entity or its QSE receives new information about an activity or condition that may limit or impede normal natural gas deliveries and materially increases the risk of Generation Resource unavailability during the summer Peak Load Season, the Resource Entity shall disclose that information to ERCOT as soon as practicable. The Resource Entity shall use reasonable judgment to determine the risk of unavailability. When notifying ERCOT as required under this paragraph, the Resource Entity shall update the information required by paragraphs (3)(a)-(e) of the Natural Gas Pipeline Coordination section of Section 22, Attachment K, for the affected Generation Resource by sending an email to the email address designated by ERCOT.

(5) In complying with its obligations in this Section 3.21, a Resource Entity or its QSE relies upon communications with and information received from operators of natural gas pipelines directly connected to the Resource Entity's Generation Resource. The Resource Entity or its QSE shall act in good faith to request the required information and,

as soon as practicable, share with each other any information received from a natural gas pipeline operator required to be disclosed to ERCOT under Section 3.21. The Resource Entity or its QSE need not warrant the accuracy or completeness of information received from the natural gas pipeline operator and subsequently disclosed to ERCOT.

3.22 Subsynchronous Resonance

(1) All series capacitors shall have automatic Subsynchronous Resonance (SSR) protective relays installed and shall have remote bypass capability. The SSR protective relays shall remain in-service when the series capacitors are in-service.

3.22.1 Subsynchronous Resonance Vulnerability Assessment

(1) In the SSR vulnerability assessment, each transmission circuit is considered as a single Outage. A common tower Outage of two circuits or the Outage of a double-circuit transmission line will be considered as two transmission Outages.

3.22.1.1 Existing Generation Resource Assessment

(1) ERCOT shall perform a one-time SSR vulnerability assessment on all existing Generation Resources as described in paragraphs (a) through (f) below. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, on or before August 12, 2013.

(a) ERCOT shall perform a topology-check on all existing Generation Resources.

(b) If during the topology-check ERCOT determines that an existing Generation Resource will become radial to a series capacitor(s) in the event of less than 14 concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria, and will provide the frequency scan assessment results to the affected Resource Entity.

(c) If the frequency scan assessment described in paragraph (b) above indicates potential SSR vulnerability, the Transmission Service Provider(s) (TSP(s)) that owns the affected series capacitor(s), in coordination with the interconnecting TSP, shall perform a detailed SSR analysis in accordance with Section 3.22.2 to determine SSR vulnerability, unless ERCOT, in consultation with and in agreement with of the affected TSP(s) and the affected Resource Entity, determines the frequency scan assessment is sufficient to determine the SSR vulnerability.

(d) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP(s) that owns the affected series capacitor(s) shall coordinate with the interconnecting TSP, ERCOT, and the affected Resource Entity to develop and implement SSR Mitigation on the ERCOT transmission system.

(e) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring.

(f) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

3.22.1.2 Generation Resource or Energy Storage Resource Interconnection Assessment

(1) In the security screening study for a Generation Resource Interconnection or Change Request, ERCOT will perform a topology-check and determine if the Generation Resource or Energy Storage Resource (ESR) will become radial to a series capacitor(s) in the event of fewer than 14 concurrent transmission Outages.

(2) If ERCOT identifies that a Generation Resource or ESR will become radial to a series capacitor(s) in the event of fewer than 14 concurrent transmission Outages, the interconnecting TSP shall perform an SSR study including frequency scan assessment and/or detailed SSR assessment for the Interconnecting Entity (IE) in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria, to determine SSR vulnerability. The SSR study shall determine which system configurations create vulnerability to SSR. Alternatively, if the IE can demonstrate to ERCOT's and the interconnecting TSP's satisfaction that the Generation Resource or ESR is not vulnerable to SSR, then the interconnecting TSP is not required to perform the SSR study. If an SSR study is conducted, the interconnecting TSP shall submit it to ERCOT upon completion and shall include any SSR Mitigation plan developed by the IE that has been reviewed by the TSP.

(3) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of six or fewer concurrent transmission Outages, the IE shall develop an SSR Mitigation plan, provide it to the interconnecting TSP for review and inclusion in the TSP's SSR study report to be approved by ERCOT, and implement the SSR Mitigation prior to Initial Synchronization.

(a) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of four concurrent transmission Outages, the IE may install SSR Protection in lieu of SSR Mitigation, as required by paragraph (3) above, if:

(i) The Generation Resource or ESR satisfied Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, between August 12, 2013 and March 20, 2015;

(ii) The SSR Protection is approved by ERCOT; and

(iii) The Generation Resource or ESR installs the ERCOT-approved SSR Protection prior to Initial Synchronization.

(b) For any Generation Resource or ESR that satisfied Planning Guide Section 6.9 before September 1, 2020, if the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, the IE may elect not to develop or implement an SSR Mitigation plan, in which case ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring. The IE shall provide ERCOT written Notice of any such election before the Generation Resource or ESR achieves Initial Synchronization, and the Generation Resource or ESR shall not be permitted to proceed to Initial Synchronization until ERCOT has implemented SSR monitoring.

(4) ERCOT shall respond with its comments or approval of an SSR study report, which should include any required SSR Mitigation plan, within 30 days of receipt. ERCOT comments should be addressed as soon as practicable by the TSP, and any action taken in response to ERCOT's comments on an SSR study report shall be subject to further ERCOT review and approval. Upon approval of the SSR study report, ERCOT shall notify the interconnecting TSP, and the interconnecting TSP shall provide the approved SSR study report to the IE.

3.22.1.3 Transmission Project Assessment

(1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSR vulnerability assessment, including a topology-check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. The TSP shall include a summary of the results of this assessment in the project submission to the Regional Planning Group (RPG) pursuant to Section 3.11.4, Regional Planning Group Project Review Process. For Tier 4 projects that include Transmission Facilities connecting to or operating at 345 kV, the TSP shall provide the SSR assessment for ERCOT's review. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9 at the time the Transmission Facilities are proposed.

(2) If while performing the independent review of a transmission project, ERCOT determines that the transmission project may cause an existing Generation Resource or a Generation Resource satisfying Planning Guide Section 6.9 at the time the transmission project is proposed to become vulnerable to SSR, ERCOT shall perform an SSR vulnerability assessment, including topology-check and frequency scan in accordance with Section

3.22.2 if such an assessment was not included in the project submission. ERCOT shall include a summary of the results of this assessment in the independent review.

(3) If the frequency scan assessment in paragraphs (1) or (2) above indicates potential SSR vulnerability in accordance with Section 3.22.2, the TSP(s) that owns the affected series capacitor(s), in coordination with the TSP proposing the Transmission Facilities, shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(4) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(5) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and implement SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(6) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(7) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

3.22.1.4 Annual SSR Review

(1) ERCOT shall perform an SSR review annually. The annual review shall include the following elements:

  (a) The annual review shall include a topology-check applying the system network topology that is consistent with a year 3 Steady State Working Group (SSWG) base case developed in accordance with Planning Guide Section 6.1, Steady-State Model Development. ERCOT shall post the SSR annual topology-check report to the Market Information System (MIS) Secure Area by May 31 of each year.

  (b) If ERCOT identifies that a Generation Resource will become radial to series capacitors(s) in the event of less than 14 concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. ERCOT shall prepare a report to summarize the results of the frequency scan assessment and provide it to the Resource Entity and the affected TSP.

(i) If the frequency scan assessment described in paragraph (b) above shows the Generation Resource has potential SSR vulnerability in the event of six or fewer concurrent transmission Outages, the TSP(s) that owns the affected series capacitor compensated Transmission Element in coordination with the interconnecting TSP shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(ii) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(iii) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor compensated Transmission Element shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and install SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(iv) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of energization of the transmission project or the Initial Synchronization of the Generation Resource.

(v) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline.

3.22.2 Subsynchronous Resonance Vulnerability Assessment Criteria

(1) A Generation Resource is considered to be potentially vulnerable to SSR in the topology-check if a Generation Resource will become radial to a series capacitors(s) in the event of less than 14 concurrent transmission Outages. A frequency scan assessment and/or a detailed SSR assessment shall be required to screen for system conditions causing potential SSR vulnerability.

(2) In determining whether a Generation Resource is considered to be potentially vulnerable to SSR in the frequency scan assessment results, the following criteria shall be considered:

(a) Induction Generator Effect (IGE) and Subsynchronous Control Interaction (SSCI):

(i) When considering the total impedance of the generator and the applicable part of the ERCOT System, if the total resistance is negative at a reactance crossover of zero Ohms from negative to positive with increasing frequency, then the generator is considered to be potentially vulnerable to IGE/SSCI;

(b) Torsional Interaction:

(i) If the sum of the electrical damping (De) plus the mechanical damping (Dm) results in a negative value then the generator is potentially vulnerable to Torsional Interaction. Dm at +/- 1 Hz of the modal frequency may be utilized to compare to De; and

(c) Torque Amplification:

(i) When considering the total impedance of the generator and the ERCOT system, if a 5% or greater reactance dip, or a reactance crossover of zero Ohms from negative to positive with increasing frequency, occurs within a +/- 3 Hz complement of the modal frequency, then the generator is considered to be potentially vulnerable to Torque Amplification. The percentage of a reactance dip is on the basis of the reactance maximum at the first inflection point of the dip where the reactance begins to decrease with increasing frequency.

(3) The detailed SSR assessment shall include an electromagnetic transient program analysis or similar analysis. A Generation Resource is considered to be vulnerable to SSR if any of the following criteria are met:

(a) The SSR vulnerability results in more than 50% of fatigue life expenditure over the expected lifetime of the unit;

(i) If the fatigue life expenditure is not available, the highest torsional torque caused by SSR is more than 110% of the torque experienced during a transmission fault with the series capacitors bypassed;

(b) The oscillation, if occurred, is not damped; or

(c) The oscillation, if occurred, results in disconnection of any transmission and generation facilities.

3.22.3 Subsynchronous Resonance Monitoring

(1) For purposes of SSR monitoring, a common tower Outage loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater is considered as one contingency.

(2) ERCOT's responsibilities for SSR monitoring shall consist of the following activities if a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages identified in the SSR vulnerability assessment and does not implement SSR Mitigation:

(a) ERCOT shall identify the combinations of Outages of Transmission Elements that may result in SSR vulnerability and provide these Transmission Elements to the affected Resource Entity and its interconnected TSP;

(b) ERCOT shall monitor the status of these Transmission Elements identified in paragraph (a) above;

(c) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being three contingencies away from SSR vulnerability, ERCOT will identify options for mitigation that would be implemented if an additional transmission Outage were to occur, including communications with TSPs to determine potential Outage cancellations and time estimates to reinstate Transmission Facilities;

(d) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two contingencies away from SSR vulnerability, ERCOT shall take action to mitigate SSR vulnerability to the affected Generation Resource. ERCOT shall consider the actions in the following order unless reliability considerations dictate a different order. Actions that may be considered are:

(i) No action if the affected Generation Resource is equipped with SSR Protection and has elected for ERCOT to forego action to mitigate SSR vulnerability;

(ii) Coordinate with TSPs to withdraw or restore an Outage within eight hours if feasible;

(iii) If the actions described in (i) and (ii) above are not feasible, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitors(s); or

(iv) Other actions specific to the situation, including, but not limited to, Verbal Dispatch Instruction (VDI) to the Resource's Qualified Scheduling Entity (QSE).

(e) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being one contingency away from SSR vulnerability, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitor(s).

(f) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two or less contingencies away from SSR vulnerability, ERCOT shall notify the QSE representing the affected Generation Resource by voice communication as soon as practicable that the SSR vulnerability scenario has occurred; initiate the mitigation actions described in paragraphs (2)(d)(i) through (iv) above; and provide additional notifications to the QSE of each relevant topology change until the affected Generation Resource(s) is at least three contingencies away from SSR vulnerability.

3.23 Agreements between ERCOT and other Control Area Operators

(1) Prior to executing any agreement with another Control Area Operator concerning coordination of Switchable Generation Resources, Direct Current Ties (DC Ties), Block Load Transfers (BLTs), or other operational issues, ERCOT shall, to the extent possible, provide Notice to all Market Participants of such agreement and at least 14 days to comment. Amendments or modifications to such existing agreements shall also comply with this provision.

(2) ERCOT shall consider all comments received in response to the Notice and, to the extent time allows, discuss its acceptance or rejection of comments with the Technical Advisory Committee (TAC) and the ERCOT Board prior to execution.

(3) ERCOT shall provide Notice to all Market Participants following execution of any such agreement within two Business Days.

ERCOT Nodal Protocols

Section 4: Day-Ahead Operations

December 1, 2022

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4 DAY-AHEAD OPERATIONS

4.1 Introduction

(1) The Day-Ahead Market (DAM) is a daily, co-optimized market in the Day-Ahead for Ancillary Service capacity and forward financial energy and congestion transactions.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) The Day-Ahead Market (DAM) is a daily, co-optimized market in the Day-Ahead for forward financial energy, Ancillary Services, and congestion transactions.

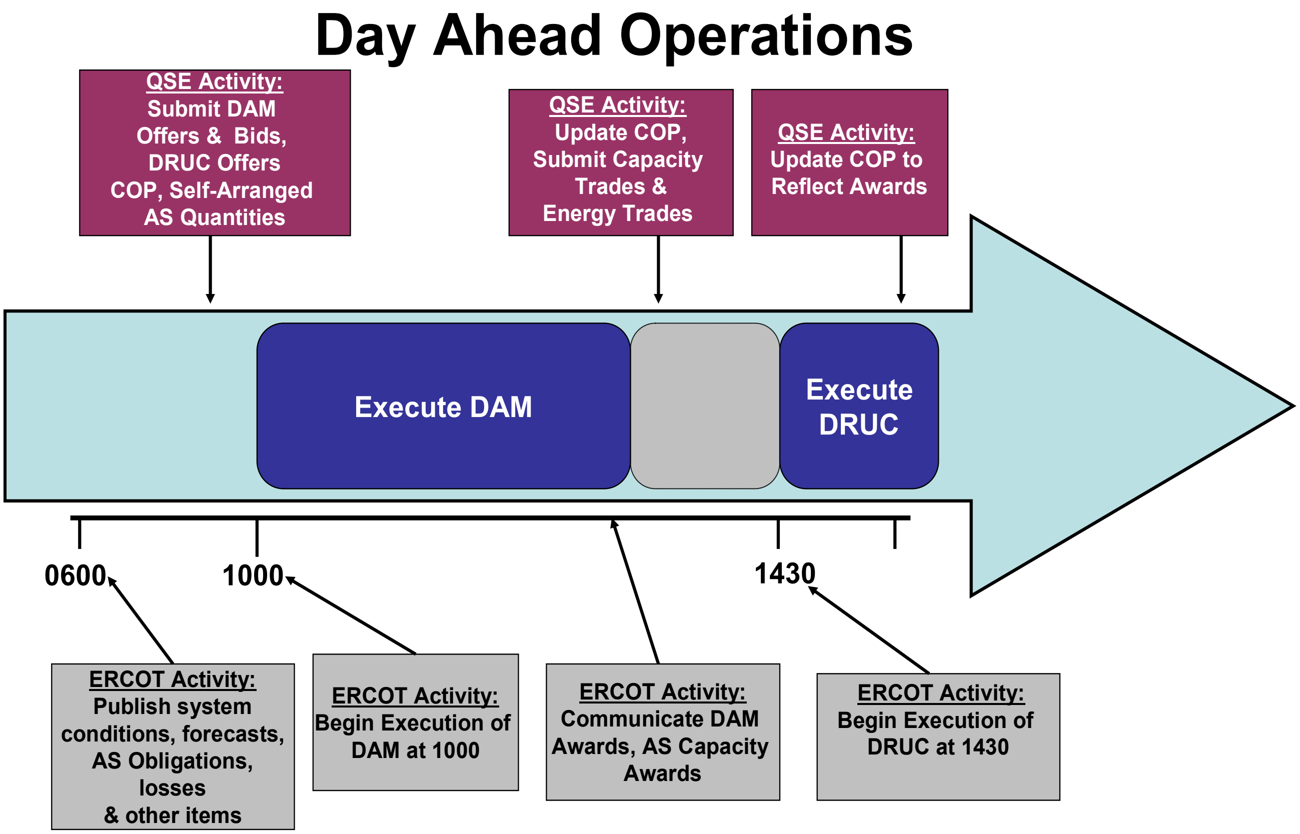
(2) Participation in the DAM is voluntary.

(3) DAM energy settlements use DAM Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a one-hour Settlement Interval using the Locational Marginal Prices (LMPs) from DAM. In contrast, the Real-Time energy settlements use Real-Time Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a 15-minute Settlement Interval.

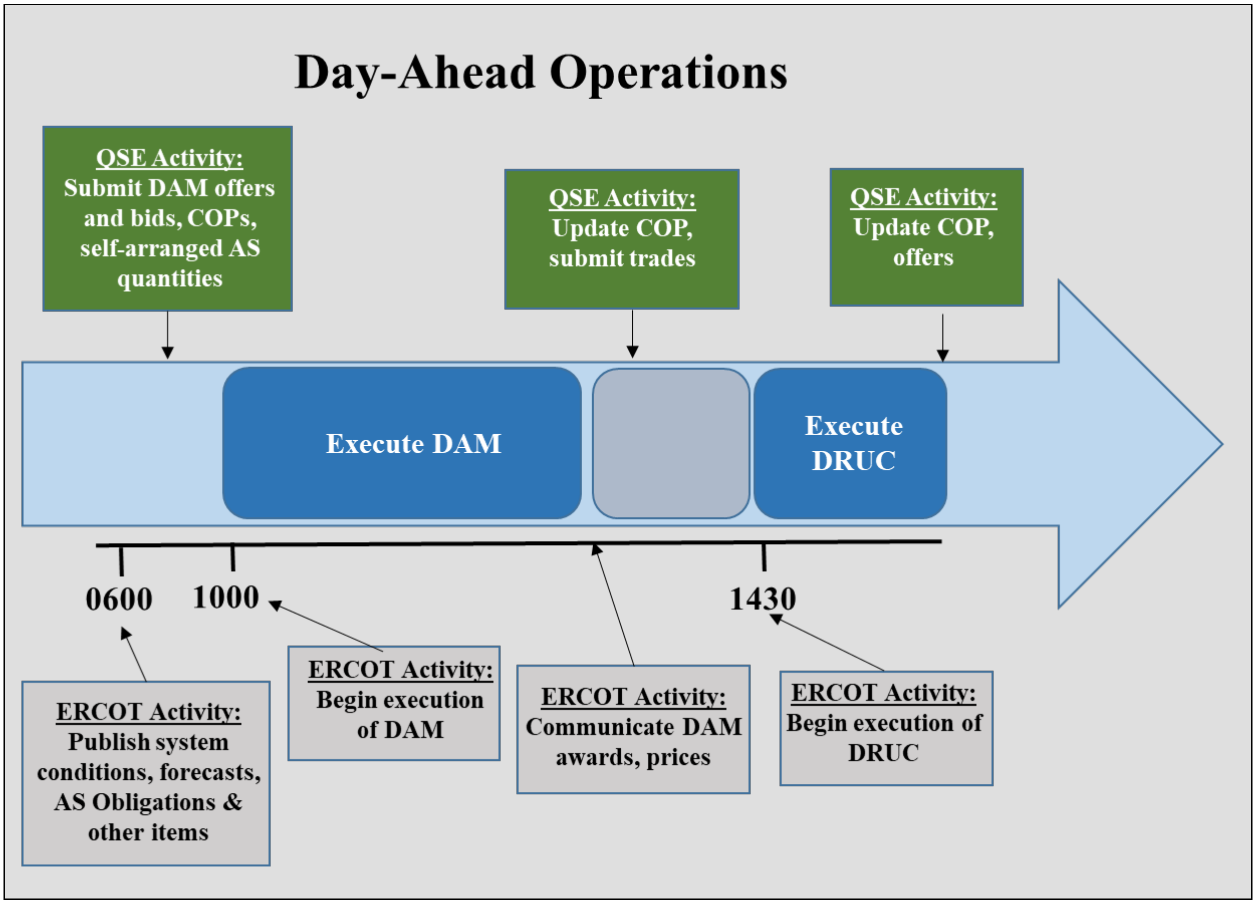
(4) To the extent that the ERCOT CEO or designee determines that Market Participant activities have produced an outcome inconsistent with the efficient operation of the ERCOT administered markets as defined in subsection (c)(2) of P.U.C. SUBST. R. 25.503, Oversight of Wholesale Market Participants, ERCOT may prohibit the activity by Notice for a period beginning on the date of the Notice and ending no later than 45 days after the date of the Notice. ERCOT may issue subsequent Notices on the same activity. The ERCOT CEO may deem any Nodal Protocol Revision Request (NPRR) designed to correct the activity or issues affecting the activity as Urgent pursuant to Section 21.5, Urgent and Board Priority Nodal Protocol Revision Requests and System Change Requests.

4.1.1 Day-Ahead Timeline Summary

(1) The figure below shows the major activities that occur in the Day-Ahead:



[NPRR1008: Replace the figure above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]



4.1.2 Day-Ahead Process and Timing Deviations

(1) ERCOT may temporarily revise the DAM transaction deadline or the time for communicating DAM results when necessary to ensure, to the greatest extent practicable, that the DAM clearing process completes. In such an event, ERCOT shall immediately issue an Advisory and notify all Qualified Scheduling Entities (QSEs) of the following:

(a) Details of the affected timing and procedures;

(b) Details of interim requirements, if any exist;

(c) An estimate of the period for which the interim requirements apply; and

(d) Reasons for the temporary variation.

(2) Subject to the principles set forth in paragraph (3) below, ERCOT may omit any procedure or take any manual action necessary to ensure, to the greatest extent practicable, that the DAM clearing process completes by 1900 in the Day-Ahead. Should ERCOT omit any such procedure or take any such manual action, ERCOT will issue a Market Notice no later than 1700 Central Prevailing Time (CPT) on the next Business Day that details the omitted procedures or manual actions taken by ERCOT and

ERCOT's explanation as to why they were necessary. If the manual action taken by ERCOT requires ERCOT to omit bids or offers submitted by a particular QSE, ERCOT will provide notification to that QSE prior to taking the manual action, so long as providing such notice will not delay completion of the DAM beyond 1900 in the Day-Ahead.

(3) When omitting a procedure or taking a manual action under paragraph (2) above, ERCOT will act in accordance with the following principles:

(a) ERCOT will only act in cases in which it reasonably believes that intervention is necessary in order to complete DAM by 1900;

(b) ERCOT will seek to minimize impacts to Market Participants and will only remove transactions from the DAM as a last resort; when ERCOT believes a QSE's transactions need to be removed, either in whole or in part, in order to complete the DAM clearing process, ERCOT will prioritize the removal in reverse order based on submittal time, where the QSE's most recently submitted transactions are prioritized before the removal of the earliest submitted transactions; however, the number of transactions removed will be at ERCOT's discretion, subject to the principles set forth in this paragraph;

(c) Approval to act will be obtained from the applicable ERCOT executive or designee; and

(d) ERCOT will not publish a DAM in which no transmission constraints are evaluated.

(4) Should ERCOT omit a procedure or take manual action pursuant to paragraph (2) above, and a Market Participant is directly impacted by such ERCOT action or omission, the Market Participant may seek relief as specifically provided for under Section 9.14.10, Settlement for Market Participants Impacted by Omitted Procedures or Manual Actions to Resolve the DAM. A Market Participant will only be entitled relief upon ERCOT's determination that ERCOT's action or omission pursuant to paragraph (2) above was the sole cause of the Market Participant's injury, and the monetary value of the direct impact can be accurately determined by ERCOT. Such relief is not available in the case that ERCOT aborts all or part of the Day-Ahead process. A Market Participant may only seek relief due to ERCOT's omission of a procedure or manual action under paragraph (2) above in the following circumstances:

(a) ERCOT removed the Market Participant's bid(s) or offer(s);

(b) ERCOT failed to award the Market Participant's bid(s) or offer(s); or

(c) ERCOT de-energized the Market Participant's Resource(s) in the base case.

(5) If ERCOT is unable to execute the Day-Ahead process prior to 1900 in the Day-Ahead, ERCOT may abort all or part of the Day-Ahead process and require all schedules and

trades to be submitted in the Adjustment Period. In that event, ERCOT shall issue a Watch and notify all QSEs of the following:

(a) Details of the affected timing and procedures;

(b) Details of any interim requirements, including the requirements described in Section 5.2.2.2, RUC Process Timeline After an Aborted Day-Ahead Market;

(c) An estimate of the period for which the interim requirements apply; and

[NPRR1008: Delete items (b) and (c) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(d) Reasons for the temporary variation.

(6) If ERCOT is unable to operate the Adjustment Period process, then ERCOT may abort the Adjustment Period process and operate under its Operating Period procedures.

4.2 ERCOT Activities in the Day-Ahead

4.2.1 Ancillary Service Plan and Ancillary Service Obligation

4.2.1.1 Ancillary Service Plan

(1) ERCOT shall analyze the expected Load conditions for the Operating Day and develop an Ancillary Service Plan that identifies the Ancillary Service MW necessary for each hour of the Operating Day. The MW of each Ancillary Service required may vary from hour to hour depending on ERCOT System conditions. ERCOT must post the Ancillary Service Plan to the ERCOT website by 0600 of the Day-Ahead.

(2) If ERCOT determines that an Emergency Condition may exist that would adversely affect ERCOT System reliability, it may change the percentage of Load Resources that are allowed to provide Responsive Reserve (RRS) from the monthly amounts determined previously, as described in Section 3.16, Standards for Determining Ancillary Service Quantities, and must post any change in the percentage to the ERCOT website by 0600 of the Day-Ahead.

[NPRR863: Replace paragraph (2) above with the following upon system implementation:]

(2) If ERCOT determines that an Emergency Condition may exist that would adversely affect ERCOT System reliability, it may change the percentage of Load Resources that are allowed to provide ERCOT Contingency Reserve Service (ECRS) and Responsive Reserve (RRS) from the monthly amounts determined previously, as described in

Section 3.16, Standards for Determining Ancillary Service Quantities, and must post any change in the percentage to the ERCOT website by 0600 of the Day-Ahead.

(3) ERCOT shall determine the total required amount of each Ancillary Service under Section 3.16, or use its operational judgment and experience to change the daily quantity of each required Ancillary Service.

(4) ERCOT shall include in the Ancillary Service Plan enough capacity to automatically control frequency with the intent to meet North American Electric Reliability Corporation (NERC) Reliability Standards.

(5) Once specified by ERCOT for an hour and published on the ERCOT website, Ancillary Service quantity requirements for an Operating Day may not be decreased.

[NPRR1008: Insert paragraph (6) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) ERCOT shall create an Ancillary Service Demand Curve (ASDC) for each Ancillary Service as described in Section 4.4.12, Determination of Ancillary Service Demand Curves. ERCOT must post the ASDCs to the ERCOT website by 0600 of the Day-Ahead. If ERCOT changes the Ancillary Service Plan per Section 6.4.9.1.2, Changes to Operating Day Ancillary Service Plan, the ASDCs reflecting the change to the Ancillary Service Plan will be posted to the ERCOT website.

4.2.1.2 Ancillary Service Obligation Assignment and Notice

(1) ERCOT shall assign part of the Ancillary Service Plan quantity, by service, by hour, to each Qualified Scheduling Entity (QSE) based on its Load Serving Entity (LSE) Load Ratio Shares (LRSs) (including the shares for Direct Current Tie (DC Tie) exports) aggregated by hour to the QSE level. If the resultant QSE-level share is negative, the QSE’s share will be set to zero and all other QSE shares will be adjusted on a pro rata basis such that the sum of all shares is equal to one. The resulting Ancillary Service quantity for each QSE, by service, by hour, is called its Ancillary Service Obligation. ERCOT shall base the QSE Ancillary Service allocation on the QSE to LSE relationships for the operating date and on the hourly LSE LRSs from the Real-Time Market (RTM) data used for Initial Settlement for the same hour and day of the week, for the most recent day for which Initial Settlement data is available, multiplied by the quantity of that service required in the Day-Ahead Ancillary Service Plan. The Ancillary Service Obligation defined shall be adjusted based on the most current real time settlement and resettlement data for the Operating Day for which the Ancillary Service was procured.

(2) By 0600 of the Day-Ahead, ERCOT shall notify each QSE of its Ancillary Service Obligation for each service and for each hour of the Operating Day.

(3) By 0600 of the Day-Ahead, ERCOT shall post on the Market Information System (MIS) Certified Area each QSE's LRS used for the Ancillary Service Obligation calculation.

[NPRR1008: Replace Section 4.2.1.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.2.1.2 Ancillary Service Obligation Assignment and Notice

(1) ERCOT shall assign part of the Ancillary Service Plan quantity, or total Ancillary Service procurement quantity, if different, by service, by hour, to each Qualified Scheduling Entity (QSE) based on its Load Serving Entity (LSE) Load Ratio Shares (LRSs) (including the shares for Direct Current Tie (DC Tie) exports) aggregated by hour to the QSE level. If the resultant QSE-level share is negative, the QSE's share will be set to zero and all other QSE shares will be adjusted on a pro rata basis such that the sum of all shares is equal to one. The resulting Ancillary Service quantity for each QSE, by service, by hour, is called its Ancillary Service Obligation. ERCOT shall base the QSE Ancillary Service allocation on the QSE to LSE relationships for the operating date and on the hourly LSE LRSs from the Real-Time Market (RTM) data used for Initial Settlement for the same hour and day of the week, for the most recent day for which Initial Settlement data is available, multiplied by the quantity of that service required in the Day-Ahead Ancillary Service Plan. The Ancillary Service Obligation defined shall be adjusted based on the most current real time settlement and resettlement data for the Operating Day for which the Ancillary Service was procured.

(2) By 0600 of the Day-Ahead, ERCOT shall notify each QSE of its advisory Ancillary Service Obligation for each service and for each hour of the Operating Day, based on the Ancillary Service Plan, as well as that QSE's proportional limit for any Self-Arranged Ancillary Services as set forth in Section 3.16, Standards for Determining Ancillary Service Quantities.

(3) By 0600 of the Day-Ahead, ERCOT shall post on the Market Information System (MIS) Certified Area each QSE's LRS used for both the advisory and final Ancillary Service Obligation calculations.

(4) The minimum Ancillary Service Obligation quantity will be 0.1 MW and will apply to both advisory and final values.

(5) After DAM has published, ERCOT shall notify each QSE of its final Ancillary Service Obligation based on the total DAM Ancillary Service procurement quantity, comprised of DAM Ancillary Service awards and Self-Arranged Ancillary Service Quantities for each service and for each hour of the Operating Day.

4.2.2 *Wind-Powered Generation Resource Production Potential*

(1) ERCOT shall produce and update hourly a Short-Term Wind Power Forecast (STWPF) that provides a rolling 168-hour hourly forecast of wind production potential for each Wind-powered Generation Resource (WGR). ERCOT shall produce and post to the ERCOT website every five minutes an Intra-Hour Wind Power Forecast (IHWPF) by wind region that provides a forecast of ERCOT-wide wind production potential for each five-minute interval over the next two hours from each forecast model. The posting shall indicate which forecast model was being used by ERCOT for Generation To Be Dispatched (GTBD) calculation purposes. ERCOT shall produce and update an hourly Total ERCOT Wind Power Forecast (TEWPF) providing a probability distribution of the hourly production potential from all wind-power in ERCOT for each of the next 168 hours. Each Generation Entity that owns a WGR shall install and telemeter to ERCOT the site-specific meteorological information that ERCOT determines is necessary to produce the STWPF and TEWPF forecasts. ERCOT shall establish procedures specifying the accuracy requirements of WGR meteorological information telemetry.

[NPRR1029: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall produce and update hourly a Short-Term Wind Power Forecast (STWPF) that provides a rolling 168-hour hourly forecast of wind production potential for each Wind-powered Generation Resource (WGR) and for each wind generation component of a DC-Coupled Resource. ERCOT shall produce and post to the ERCOT website every five minutes an Intra-Hour Wind Power Forecast (IHWPF) by wind region that provides a forecast of ERCOT-wide wind production potential for each five-minute interval over the next two hours from each forecast model. The posting shall indicate which forecast model was being used by ERCOT for Generation To Be Dispatched (GTBD) calculation purposes. ERCOT shall produce and update an hourly Total ERCOT Wind Power Forecast (TEWPF) providing a probability distribution of the hourly production potential from all wind-power in ERCOT for each of the next 168 hours. A Resource Entity with a WGR or DC-Coupled Resource that has a wind generation component shall install equipment to enable telemetry of site-specific meteorological information that ERCOT determines is necessary to produce the STWPF and TEWPF forecasts, and the Resource Entity's QSE shall telemeter such information and Resource status information to ERCOT. ERCOT shall establish procedures specifying the accuracy requirements of meteorological information telemetry for WGRs and DC-Coupled Resources with a wind generation component.

(2) ERCOT shall use the probabilistic TEWPF and select the forecast that the actual total ERCOT WGR production is expected to exceed 50% of the time (50% probability of exceedance forecast). To produce the STWPF, ERCOT will allocate the TEWPF 50% probability of exceedance forecast to each WGR such that the sum of the individual STWPF forecasts equal the TEWPF forecast. The updated STWPF forecasts for each hour for each WGR are to be used as input into each Reliability Unit Commitment (RUC)

process as per Section 5, Transmission Security Analysis and Reliability Unit Commitment.

[NPRR1029: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall use the probabilistic TEWPF and select the forecast that the actual total ERCOT production of WGRs and the wind generation components of all DC-Coupled Resources is expected to exceed 50% of the time (50% probability of exceedance forecast). To produce the STWPF, ERCOT will allocate the TEWPF 50% probability of exceedance forecast to each WGR and each wind generation component of a DC-Coupled Resource such that the sum of the individual STWPF forecasts equal the TEWPF forecast. The updated STWPF forecasts for each hour for each WGR and each wind generation component of a DC-Coupled Resource are to be used as input into each Reliability Unit Commitment (RUC) process as per Section 5, Transmission Security Analysis and Reliability Unit Commitment.

(3) ERCOT shall produce the Wind-powered Generation Resource Production Potential (WGRPP) forecasts using the information provided by WGR owners including WGR availability, meteorological information, and Supervisory Control and Data Acquisition (SCADA).

[NPRR1029: Replace paragraph (3) above with the following upon system implementation:]

(3) ERCOT shall produce the Wind-powered Generation Resource Production Potential (WGRPP) forecasts using the information provided by Resource Entities and QSEs representing WGRs and DC-Coupled Resources with wind generation components, including Resource availability, meteorological information, and Supervisory Control and Data Acquisition (SCADA).

(4) Each hour, ERCOT shall provide, through the Messaging System, the STWPF and WGRPP forecasts for each WGR to the QSE that represents that WGR and shall post each STWPF and WGRPP forecast on the MIS Certified Area.

[NPRR1029: Replace paragraph (4) above with the following upon system implementation:]

(4) Each hour, ERCOT shall provide, through the Messaging System, the STWPF and WGRPP forecasts for each WGR and each wind generation component of a DC-Coupled Resource to the QSE that represents that WGR or DC-Coupled Resource and shall post each STWPF and WGRPP forecast on the MIS Certified Area.

(5) Each hour, ERCOT shall post to the ERCOT website, on a system-wide and regional basis the hourly actual wind power production, STWPF, WGRPP, and aggregate Current Operating Plan (COP) High Sustained Limits (HSLs) for On-Line WGRs for a rolling historical 48-hour period. The system-wide and regional STWPF, WGRPP, and aggregate COP HSLs for On-Line WGRs will also be posted for the rolling future 168-hour period. ERCOT shall retain the STWPF and WGRPP for each hour.

[NPRR1029: Replace paragraph (5) above with the following upon system implementation:]

(5) Each hour, ERCOT shall post to the ERCOT website, on a system-wide and regional basis the hourly actual wind power production, STWPF, WGRPP, and aggregate Current Operating Plan (COP) High Sustained Limits (HSLs) for On-Line WGRs and the wind generation components of DC-Coupled Resources for a rolling historical 48-hour period. The system-wide and regional STWPF, WGRPP, and aggregate COP HSLs for On-Line WGRs and the wind generation components of DC-Coupled Resources will also be posted for the rolling future 168-hour period. ERCOT shall retain the STWPF and WGRPP for each hour.

(6) Each hour, ERCOT shall post to the ERCOT website the hourly system-wide and regional STWPF and WGRPP values produced by each forecast model for On-Line WGRs for the rolling historical 48-hour period and the rolling future 168-hour period. ERCOT's posting shall also indicate which forecast model it is using for each region to populate COPs.

[NPRR1029: Replace paragraph (6) above with the following upon system implementation:]

(6) Each hour, ERCOT shall post to the ERCOT website the hourly system-wide and regional STWPF and WGRPP values produced by each forecast model for On-Line WGRs and the wind generation components of DC-Coupled Resources for the rolling historical 48-hour period and the rolling future 168-hour period. ERCOT's posting shall also indicate which forecast model it is using for each region to populate COPs.

(7) Every five minutes, ERCOT shall post to the ERCOT website, on a system-wide and regional basis, five-minute actual wind power production for a rolling historical 60-minute period.

4.2.3 PhotoVoltaic Generation Resource Production Potential

(1) ERCOT shall produce and update hourly a Short-Term PhotoVoltaic Power Forecast (STPPF) that provides a rolling 168-hour hourly forecast of PhotoVoltaic production potential for each PhotoVoltaic Generation Resource (PVGR). ERCOT shall produce

and post to the ERCOT website every five minutes an Intra-Hour PhotoVoltaic Power Forecast (IHPPF) by PhotoVoltaic region that provides a forecast of ERCOT-wide PhotoVoltaic production potential for each five-minute interval over the next two hours from each forecast model. The posting shall indicate which forecast model was being used by ERCOT for GTBD calculation purposes. ERCOT shall produce and update an hourly Total ERCOT PhotoVoltaic Power Forecast (TEPPF) providing a probability distribution of the hourly production potential from all PhotoVoltaic Generation Resources in ERCOT for each of the next 168 hours. Each Generation Entity that owns a PVGR shall install and telemeter to ERCOT the site-specific meteorological information that ERCOT determines is necessary to produce the STPPF and TEPPF forecasts. ERCOT shall establish procedures specifying the accuracy requirements of PVGR meteorological information telemetry.

[NPRR1029: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall produce and update hourly a Short-Term PhotoVoltaic Power Forecast (STPPF) that provides a rolling 168-hour hourly forecast of PhotoVoltaic (PV) production potential for each PhotoVoltaic Generation Resource (PVGR) and for the PV component of each DC-Coupled Resource. ERCOT shall produce and post to the ERCOT website every five minutes an Intra-Hour PhotoVoltaic Power Forecast (IHPPF) by PhotoVoltaic region that provides a forecast of ERCOT-wide PhotoVoltaic production potential for each five-minute interval over the next two hours from each forecast model. The posting shall indicate which forecast model was being used by ERCOT for GTBD calculation purposes. ERCOT shall produce and update an hourly Total ERCOT PhotoVoltaic Power Forecast (TEPPF) providing a probability distribution of the hourly production potential from all PhotoVoltaic Generation Resources and the PV components of all DC-Coupled Resources in ERCOT for each of the next 168 hours. A Resource Entity with a PVGR or DC-Coupled Resource that has a PV component shall install equipment to enable telemetry of site-specific meteorological information that ERCOT determines is necessary to produce the STPPF and TEPPF forecasts, and the Resource Entity’s QSE shall telemeter such information and Resource status information to ERCOT. ERCOT shall establish procedures specifying the accuracy requirements of meteorological information telemetry for PVGRs and DC-Coupled Resources with a PV component.

(2) ERCOT shall use the probabilistic TEPPF and select the forecast that the actual total ERCOT PVGR production is expected to exceed 50% of the time (50% probability of exceedance forecast). To produce the STPPF, ERCOT will allocate the TEPPF 50% probability of exceedance forecast to each PVGR such that the sum of the individual STPPF forecasts equal the TEPPF forecast. The updated STPPF forecasts for each hour for each PVGR are to be used as input into each RUC process as per Section 5, Transmission Security Analysis and Reliability Unit Commitment.

[NPRR1029: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall use the probabilistic TEPPF and select the forecast that the actual total ERCOT production of PVGRs and the PV components of DC-Coupled Resources is expected to exceed 50% of the time (50% probability of exceedance forecast). To produce the STPPF, ERCOT will allocate the TEPPF 50% probability of exceedance forecast to each PVGR and each PV component of a DC-Coupled Resource such that the sum of the individual STPPF forecasts equal the TEPPF forecast. The updated STPPF forecasts for each hour for each PVGR and each PV component of a DC-Coupled Resource are to be used as input into each RUC process as per Section 5, Transmission Security Analysis and Reliability Unit Commitment.

(3) ERCOT shall produce the PhotoVoltaic Generation Resource Production Potential (PVGRPP) forecasts using the information provided by PVGR owners including PVGR availability, meteorological information, and SCADA.

[NPRR1029: Replace paragraph (3) above with the following upon system implementation:]

(3) ERCOT shall produce the PhotoVoltaic Generation Resource Production Potential (PVGRPP) forecasts using the information provided by owners of PVGRs and DC-Coupled Resources with a PV component including Resource availability, meteorological information, and SCADA.

(4) Each hour, ERCOT shall provide, through the Messaging System, the STPPF and PVGRPP forecasts for each PVGR to the QSE that represents that PVGR and shall post each STPPF and PVGRPP forecast on the MIS Certified Area.

[NPRR1029: Replace paragraph (4) above with the following upon system implementation:]

(4) Each hour, ERCOT shall provide, through the Messaging System, the STPPF and PVGRPP forecasts for each PVGR and each DC-Coupled Resource with a PV component to the QSE that represents that PVGR or DC-Coupled Resource and shall post each STPPF and PVGRPP forecast on the MIS Certified Area.

(5) After the aggregated ERCOT PVGR capacity reaches one GW and the maximum PVGR capacity ratio of a single PVGR over the total ERCOT installed PVGR capacity is at or below 60%, each hour ERCOT shall post to the ERCOT website, on a system-wide basis the hourly actual PhotoVoltaic (PV) power production, STPPF, PVGRPP, and aggregate COP HSLs for On-Line PVGRs for a rolling historical 48-hour period. The system-wide

STPPF, PVGRPP, and aggregate COP HSLs for On-Line PVGRs will also be posted for the rolling future 168-hour period. ERCOT shall retain the STPPF and PVGRPP for each hour. However, ERCOT shall post this information no later than June 1, 2016.

[NPRR1029: Replace paragraph (5) above with the following upon system implementation:]

(5) Each hour ERCOT shall post to the ERCOT website, on a system-wide basis the hourly actual PhotoVoltaic (PV) power production, STPPF, PVGRPP, and aggregate COP HSLs for On-Line PVGRs and PV components of DC-Coupled Resources for a rolling historical 48-hour period. The system-wide STPPF, PVGRPP, and aggregate COP HSLs for On-Line PVGRs and PV components of DC-Coupled Resources shall also be posted for the rolling future 168-hour period.

(6) Each hour, ERCOT shall post to the ERCOT website the hourly system-wide and regional STPPF and PVGRPP values produced by each forecast model for On-Line PVGRs for the rolling historical 48-hour period and the rolling future 168-hour period. ERCOT's posting shall also indicate which forecast model it is using for each region to populate COPs.

[NPRR1029: Replace paragraph (6) above with the following upon system implementation:]

(6) Each hour, ERCOT shall post to the ERCOT website the hourly system-wide and regional STPPF and PVGRPP values produced by each forecast model for On-Line PVGRs and DC-Coupled Resources with a PV component for the rolling historical 48-hour period and the rolling future 168-hour period. ERCOT's posting shall also indicate which forecast model it is using for each region to populate COPs.

(7) After the aggregated ERCOT PVGR capacity reaches one GW and the maximum PVGR capacity ratio of a single PVGR over the total ERCOT installed PVGR capacity is at or below 60%, every five minutes, ERCOT shall post to the ERCOT website, on a system-wide basis, five-minute actual PV power production for a rolling historical 60-minute period. However, ERCOT shall post this information no later than June 1, 2016.

[NPRR1029: Replace paragraph (7) above with the following upon system implementation:]

(7) Every five minutes, ERCOT shall post to the ERCOT website, on a system-wide basis, five-minute actual PV power production from all PVGRs and PV components of DC-Coupled Resources for a rolling historical 60-minute period.

4.2.4 Posting Secure Forecasted ERCOT System Conditions

(1) No later than 0600 in the Day-Ahead, ERCOT shall post on the MIS Secure Area, and make available for download, the following information for the Operating Day:

(a) For each update of the Network Operations Model, the Redacted Network Operations Model in the Common Information Model (CIM) format and the companion version of Network Operations Model (unredacted) will be posted to the MIS Certified Area for Transmission Service Providers (TSPs) as described in paragraph (9) of Section 3.10.4, ERCOT Responsibilities;

(b) For each update of the Network Operations Model, differences between the posted Redacted Network Operations Model and the previous Redacted Network Operations Model as described in paragraph (4) of Section 3.10.4;

(c) Load Profiles for non-Interval Data Recorder (IDR) metered Customers;

(d) Distribution Loss Factors (DLFs) and forecasted ERCOT-wide Transmission Loss Factors (TLFs), as described in Section 13.3, Distribution Losses, and Section 13.2, Transmission Losses, for each Settlement Interval of the Operating Day;

(e) A current list of Electrically Similar Settlement Points produced from the 0600 Day-Ahead Market (DAM) study that support that creation of Power System Simulator for Engineering (PSS/E) files;

(f) A daily version of the Network Operations Model in a PSS/E format that has been exported from the Market Management System prior to 0600 representing the next Operating Day in hourly files, inclusive of:

(i) Outages from the Outage Scheduler implemented in the hourly PSS/E files;

(ii) All bus shunt MW and MVAr set to zero;

(iii) All Load MW and MVAr set to zero;

(iv) All generation MW and MVAr set to zero; and

(v) Slack bus used in the DAM shall be represented at the same bus in each case; and

(g) A daily version of supporting files for the PSS/E files supporting the Network Operations Model that has been exported from the Market Management System prior to 0600, inclusive of:

(i) Contingency definition corresponding to each hourly PSS/E file;

(ii) Generator mapping data corresponding to each hourly PSS/E file;

(iii) Mapping of all Resource Nodes and DC Tie Load Zone to the hourly PSS/E file including Private Use Network Settlement Points. This file of hourly data will also include the base case energization status of Resource Node and DC Tie Load Zone reflecting Settlement Points available for DAM clearing process;

(iv) Load mapping data corresponding to each hourly PSS/E case necessary to model all Load Zone energy transactions in the DAM;

(v) Transmission line mapping data corresponding to each hourly PSS/E files;

(vi) Transformer mapping data corresponding to each hourly PSS/E files; and

(vii) Hub mapping data corresponding to each hourly PSS/E case necessary to model all Hub energy transactions in the DAM.

4.2.4.1 Posting Public Forecasted ERCOT System Conditions

(1) No later than 0600 in the Day-Ahead, ERCOT shall post on the ERCOT website, and make available for download, the following information for the Operating Day:

(a) Weather assumptions used by ERCOT to forecast ERCOT System conditions and used in the Dynamic Rating Processor;

(b) ERCOT System, Weather Zone, Load Zone, and Study Area Load forecasts for the next seven days, by hour, and a message on update indicating any changes to the forecasts by means of the Messaging System;

(c) A current list of all Settlement Points that may be used for market processes and transactions;

(d) A mapping of Settlement Points to Electrical Buses in the Network Operations Model;

(e) A list of transmission constraints that have a high probability of binding in the Security-Constrained Economic Dispatch (SCED) or DAM; and

(f) A mapping of any Electrical Bus to another Electrical Bus for purposes of heuristic pricing as described in paragraph (8) of Section 4.5.1, DAM Clearing Process, and Section 6.6.1, Real-Time Settlement Point Prices.

4.2.5 Notice of New Types of Forecasts

(1) Before using any new type of forecast for any operational purpose, ERCOT shall issue a Market Notice stating ERCOT's intention to use that new type of forecast and shall sponsor a Nodal Protocol Revision Request (NPRR) to propose requirements for posting data for the new type of forecast.

4.2.6 ERCOT Notice of Validation Rules for the Day-Ahead

(1) ERCOT shall provide each QSE with the information necessary to pre-validate its data for DAM, including publishing validation rules for offers, bids, and trades.

4.3 QSE Activities and Responsibilities in the Day-Ahead

(1) During the Day-Ahead, a Qualified Scheduling Entity (QSE):

(a) Must submit its Current Operating Plan (COP) and update its COP as required in Section 3.9, Current Operating Plan (COP); and

(b) May submit Three-Part Supply Offers, Day-Ahead Market (DAM) Energy-Only Offers, DAM Energy Bids, Energy Trades, Self-Schedules, Capacity Trades, Direct Current Tie (DC Tie) Schedules, Ancillary Service Offers, Ancillary Service Trades, Self-Arranged Ancillary Service Quantities, and Point-to-Point (PTP) Obligation bids as specified in this Section.

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

(b) May submit Three-Part Supply Offers, Day-Ahead Market (DAM) Energy-Only Offers, DAM Energy Bids, Energy Bid/Offer Curves, Energy Trades, Self-Schedules, Capacity Trades, Direct Current Tie (DC Tie) Schedules, Resource-Specific Ancillary Service Offers, DAM Ancillary Service Only Offers, Ancillary Service Trades, Self-Arranged Ancillary Service Quantities, and Point-to-Point (PTP) Obligation bids as specified in this Section.

(2) By 0600 in the Day-Ahead, each QSE representing Reliability Must-Run (RMR) Units, Firm Fuel Supply Service (FFSS) Resources (FFSSRs), or Black Start Resources shall submit its Availability Plan to ERCOT indicating availability of RMR Units, FFSSRs, and Black Start Resources for the Operating Day and any other information that ERCOT may need to evaluate use of the units.

4.4 Inputs into DAM and Other Trades

4.4.1 Capacity Trades

(1) A Capacity Trade is the information for a Qualified Scheduling Entity (QSE)-to-QSE transaction that transfers financial responsibility for capacity between a buyer and a seller.

(2) A Capacity Trade for hours in the Operating Day that is reported to ERCOT before 1430 in the Day-Ahead creates:

(a) A capacity supply in the Day-Ahead Reliability Unit Commitment (DRUC) process for the buyer; and

(b) A capacity obligation in the DRUC process for the seller.

(3) A Capacity Trade submitted at or after 1430 in the Day-Ahead for the Operating Day creates a capacity supply or obligation in any Hourly Reliability Unit Commitment (HRUC) processes executed after the Capacity Trade is reported to ERCOT. Capacity Trades submitted after the DRUC snapshot are considered in the Adjustment Period snapshot.

(4) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Capacity Trades that are invalid Capacity Trades. The QSE may correct and resubmit any invalid Capacity Trade within the appropriate market timeline.

4.4.1.1 Capacity Trade Criteria

(1) A Capacity Trade must be submitted by a QSE and must include the following:

(a) The buying QSE;

(b) The selling QSE;

(c) The quantity in MW; and

(d) The first hour and last hour of the trade.

(2) A Capacity Trade must be confirmed by both the buyer and seller to be considered valid.

4.4.1.2 Capacity Trade Validation

(1) A validated Capacity Trade is a Capacity Trade that ERCOT has determined meets the criteria listed in Section 4.4.1.1, Capacity Trade Criteria. Only one confirmed Capacity Trade is allowed for the same buying and selling QSEs for each hour.

(2) When a Capacity Trade is reported to ERCOT, ERCOT shall notify both the buying and selling QSEs by using the Messaging System, if available, and on the Market Information System (MIS) Certified Area. ERCOT shall also post to the MIS Certified Area any unconfirmed Capacity Trades for QSEs on an hourly basis for all remaining hours of the current Operating Day and all hours of the next Operating Day.

(3) ERCOT shall continuously validate Capacity Trades and continuously display on the MIS Certified Area information that allows any QSE named in a Capacity Trade to view confirmed and unconfirmed Capacity Trades.

(4) The QSE that first reports the Capacity Trade to ERCOT is deemed to have confirmed the Capacity Trade unless it subsequently affirmatively rejects it. The QSE that first reports a Capacity Trade may reject, edit, or delete a Capacity Trade that its counterpart has not confirmed. The counterpart is deemed to have confirmed the Capacity Trade when it submits to ERCOT an identical Capacity Trade. After both the buyer and seller have confirmed a Capacity Trade, either party may reject it at any time, but the rejection is effective only for any ERCOT Settlement process for which the deadline for reporting Capacity Trades has not yet passed.

4.4.2 Energy Trades

(1) An Energy Trade is the information for a QSE-to-QSE transaction that transfers financial responsibility for energy at a Settlement Point between a buyer and a seller.

(2) An Energy Trade for hours in the Operating Day that is reported to ERCOT before 1430 in the Day-Ahead creates a capacity supply or obligation in the DRUC process. Energy Trades submitted after 1430 in the Day-Ahead for the Operating Day create a capacity supply or obligation in any HRUC processes executed after the Energy Trade is reported to ERCOT. Energy Trades submitted after the DRUC snapshot are considered in the Adjustment Period.

(3) An Energy Trade may be submitted for any Settlement Interval within an Operating Day before 1430 of the following day.

(4) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Energy Trades that are invalid Energy Trades. The QSE may correct and resubmit any invalid Energy Trade within the appropriate market timeline.

4.4.2.1 Energy Trade Criteria

(1) Each Energy Trade must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The selling QSE;

(c) The quantity of MW for each 15-minute Settlement Interval of the trade;

(d) The first and last 15-minute Settlement Intervals of the trade; and

(e) The Settlement Point of the trade.

(2) An Energy Trade must be confirmed by both the buyer and seller to be considered valid.

4.4.2.2 Energy Trade Validation

(1) A validated Energy Trade is an Energy Trade that ERCOT has determined meets the criteria listed in Section 4.4.2.1, Energy Trade Criteria. Only one confirmed Energy Trade is allowed for the same buying and selling QSEs at the same Settlement Point for each 15-minute Settlement Interval.

(2) When an Energy Trade is reported to ERCOT, ERCOT shall notify both the buying and selling QSEs by using the Messaging System, if available, and the MIS Certified Area. ERCOT shall also post to the MIS Certified Area any unconfirmed Energy Trades for QSEs on an hourly basis for all remaining hours of the current Operating Day and all hours of the next Operating Day.

(3) ERCOT shall continuously validate Energy Trades and continuously display on the MIS Certified Area information that allows any QSE named in an Energy Trade to view confirmed and unconfirmed Energy Trades.

(4) The QSE that first reports the Energy Trade to ERCOT is considered to have confirmed the Energy Trade unless it subsequently affirmatively rejects it. The QSE that first reports an Energy Trade may reject, edit, or delete an Energy Trade that its counterpart has not confirmed. The counterpart is deemed to have confirmed the Energy Trade when it submits an identical Energy Trade. After both the buyer and seller have confirmed an Energy Trade, either party may reject it at any time, but the rejection is effective only for any ERCOT process for which the deadline for reporting Energy Trades has not yet passed.

4.4.3 Self-Schedules

(1) A Self-Schedule is the information that a QSE submits for Real-Time Settlement that specifies the amount of the QSE's energy supply at a specified source Settlement Point to be used to meet the QSE's energy obligation at a specified sink Settlement Point.

(2) A Self-Schedule may be submitted for any Settlement Interval before the end of the Adjustment Period for that Settlement Interval.

(3) As soon as practicable, ERCOT shall notify the QSE through the Messaging System of any of its Self-Schedules that are invalid Self-Schedules. The QSE may correct and resubmit any invalid Self-Schedule within the appropriate market timeline.

4.4.3.1 Self-Schedule Criteria

(1) Each Self-Schedule must be reported by a QSE and must include the following information:

(a) The name of the QSE;

(b) The quantity of MW for each 15-minute Settlement Interval of the schedule;

(c) The first and last 15-minute Settlement Intervals of the schedule;

(d) The source Settlement Point of the schedule; and

(e) The sink Settlement Point of the schedule.

4.4.3.2 Self-Schedule Validation

(1) A validated Self-Schedule is a Self-Schedule that ERCOT has determined meets the criteria listed in Section 4.4.3.1, Self-Schedule Criteria.

(2) ERCOT shall continuously validate Self-Schedules and continuously display on the MIS Secure Area information that allows the QSE named in a Self-Schedule to view validated Self-Schedules.

4.4.4 DC Tie Schedules

(1) All schedules between the ERCOT Control Area and a non-ERCOT Control Area(s) over Direct Current Tie(s) (DC Ties(s)), must be implemented under these Protocols, any applicable North American Electric Reliability Corporation (NERC) Reliability Standards, North American Energy Standards Board (NAESB) Practice Standards, and operating agreements between ERCOT and the Comision Federal de Electricidad (CFE).

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) All Direct Current Tie (DC Tie) Schedules between the ERCOT Control Area and a non-ERCOT Control Area(s) must be implemented in accordance with these Protocols, any applicable North American Electric Reliability Corporation (NERC) Reliability Standards, North American Energy Standards Board (NAESB) Practice Standards, and operating agreements between ERCOT and the appropriate operating authority for the non-ERCOT Control Area.

(2) A DC Tie Schedule for hours in the Operating Day corresponding to an Electronic Tag (e-Tag) that is reported to ERCOT before 1430 in the Day-Ahead creates a capacity supply for the equivalent Resource or an obligation for the equivalent Load of the DC Tie in the DRUC process. DC Tie Schedules corresponding to e-Tags approved after 1430 in

the Day-Ahead for the Operating Day create a capacity supply or obligation in any applicable HRUC processes. DC Tie Schedules corresponding to e-Tags approved after the Reliability Unit Commitment (RUC) snapshot are considered in the Adjustment Period snapshot in accordance with the market timeline.

(3) A QSE that is an importer into ERCOT through a DC Tie in a Settlement Interval under an approved e-Tag must be treated as a Resource at that DC Tie Settlement Point for that Settlement Interval.

(4) A QSE that is an exporter from ERCOT through a DC Tie in a Settlement Interval under an approved e-Tag must be treated as a Load at the DC Tie Settlement Point for that Settlement Interval and is responsible for allocated Transmission Losses, Unaccounted for Energy (UFE), System Administration Fee, and any other applicable ERCOT fees.

(5) ERCOT shall approve any e-Tag that does not exceed the available physical capacity of the DC Tie and any limits supplied the non-ERCOT Control Area for the time period for which the e-Tag is requested unless a DC Tie Curtailment Notice is in effect for the particular DC Tie for which the e-Tag request is made. While a DC Tie Curtailment Notice is in effect, ERCOT will deny any additional e-Tag requests that would exacerbate the transmission security violations that led to that DC Tie Curtailment Notice. Notwithstanding the foregoing, ERCOT shall deny or curtail any e-Tag over any of the DC Ties if necessary to avoid causing any Entity in the ERCOT Region that is not a “public utility” as defined in the Federal Power Act (FPA), including ERCOT, to become such a public utility. If ERCOT determines that it is necessary to deny or curtail e-Tags in order to prevent any Entity from becoming a “public utility,” it shall provide notice of that determination by posting an operations message to the ERCOT website and issuing a Market Notice.

[NPRR999: Replace paragraph (5) above with the following upon project implementation of the Intra-Hour Variability (iCAT) Tool:]

(5) ERCOT shall approve any e-Tag that does not exceed the available physical capacity of the DC Tie, system ramping capability, and any limits supplied by the non-ERCOT Control Area for the time period for which the e-Tag is requested unless a DC Tie Curtailment Notice is in effect for the particular DC Tie for which the e-Tag request is made; otherwise, ERCOT shall deny the e-Tag. While a DC Tie Curtailment Notice is in effect, ERCOT will deny any additional e-Tag requests that would exacerbate the transmission security violations that led to that DC Tie Curtailment Notice. Notwithstanding the foregoing, ERCOT shall deny or curtail any e-Tag over any of the DC Ties if necessary to avoid causing any Entity in the ERCOT Region that is not a “public utility” as defined in the Federal Power Act (FPA), including ERCOT, to become such a public utility. If ERCOT determines that it is necessary to deny or curtail e-Tags in order to prevent any Entity from becoming a “public utility,” it shall provide notice of that determination by posting an operations message to the ERCOT website and issuing a Market Notice.

(6) ERCOT shall perform schedule confirmation with the applicable non-ERCOT Control Area(s) and shall coordinate the approval process for the e-Tags for the ERCOT Control Area. An e-Tag for a schedule across a DC Tie is considered approved if:

(a) All Control Areas and Transmission Service Providers (TSPs) with approval rights approve the e-Tag (active approval); or

[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(a) All Control Areas and Direct Current Tie Operators (DCTOs) with approval rights approve the e-Tag (active approval); or

(b) No Entity with approval rights over the e-Tag has denied it, and the approval time window has ended (passive approval).

(7) Using the DC Tie Schedule information corresponding to e-Tags submitted by QSEs, ERCOT shall update and maintain a Current Operating Plan (COP) for each DC Tie for which the aggregated DC Tie Schedules for that tie show a net export out of ERCOT for the applicable interval. When the net energy schedule for a DC Tie indicates an export, ERCOT shall treat the DC Tie as an Off-Line Resource and set the High Sustained Limit (HSL) and Low Sustained Limit (LSL) for that DC Tie Resource to zero. ERCOT shall monitor the associated Resource Status telemetry during the Operating Period. When the net energy schedule for a DC Tie shows a net import, the Resource HSL, High Ancillary Service Limit (HASL) and LSL must be set appropriately, considering the resulting net import.

[NPRR1008: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Using the DC Tie Schedule information corresponding to e-Tags submitted by QSEs, ERCOT shall update and maintain a Current Operating Plan (COP) for each DC Tie for which the aggregated DC Tie Schedules for that tie show a net export out of ERCOT for the applicable interval. When the net energy schedule for a DC Tie indicates an export, ERCOT shall treat the DC Tie as an Off-Line Resource and set the High Sustained Limit (HSL) and Low Sustained Limit (LSL) for that DC Tie Resource to zero. ERCOT shall monitor the associated Resource Status telemetry during the Operating Period. When the net energy schedule for a DC Tie shows a net import, the Resource HSL and LSL must be set appropriately, considering the resulting net import.

(8) A QSE exporting from ERCOT and/or importing to ERCOT through a DC Tie shall:

- (a) Secure and maintain an e-Tag service to submit e-Tags and monitor e-Tag status according to NERC requirements;
- (b) Submit e-Tags for all proposed transactions; and
- (c) Implement backup procedures in case of e-Tag service failure.

(9) ERCOT shall post a notice to the MIS Certified Area when a confirmed e-Tag is downloaded, cancelled, or curtailed by ERCOT's systems.

(10) ERCOT shall use the DC Tie e-Tag MW amounts for Settlement. The DC Tie operator shall communicate deratings of the DC Ties to ERCOT and other affected regions and all parties shall agree to any adjusted or curtailed e-Tag amounts.

[NPRR857: Replace paragraph (10) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(10) ERCOT shall use the DC Tie e-Tag MW amounts for Settlement. The DCTO shall communicate deratings of the DC Ties to ERCOT and other affected regions and all parties shall agree to any adjusted or curtailed e-Tag amounts.

(11) DC Tie Load is considered as Load for daily and hourly reliability studies, and settled as Adjusted Metered Load (AML). DC Tie Load is curtailed prior to other Load on the ERCOT System as described below, and during Energy Emergency Alert (EEA) events as set forth in Section 6.5.9.4.2, EEA Levels.

(12) DC Tie Load shall neither be curtailed by ERCOT during the Adjustment Period, nor for more than one hour at a time, except for the purpose of maintaining reliability, or as indicated in paragraphs (13), (14), (15), and (16) below.

(13) If a system operator in a non-ERCOT Control Area requests curtailment of a DC Tie Schedule due to an actual or anticipated emergency in its Control Area, ERCOT may curtail the DC Tie Schedule. If the DC Tie Schedule is curtailed, ERCOT shall post a DC Tie Curtailment Notice to the ERCOT website as soon as practicable.

(14) If a DC Tie experiences an Outage, ERCOT may curtail DC Tie Schedules that are, or that are expected to be, affected by the Outage based on system conditions and expected restoration time of the Outage. ERCOT shall post a DC Tie Curtailment Notice to the

ERCOT website as soon as practicable. Updated DC Tie limits shall be posted as required in paragraph (1) of Section 3.10.7.7, DC Tie Limits.

(15) If market-based congestion management techniques embedded in Security-Constrained Economic Dispatch (SCED) as specified in these Protocols will not be adequate to resolve one or more transmission security violations that would be fully or partially resolved by the curtailment of DC Tie Load and, in ERCOT's judgment, no approved Constraint Management Plan (CMP) is adequate to resolve those violations, ERCOT may instruct Resources to change output and, if still necessary, curtail DC Tie Load to maintain reliability and shall post a DC Tie Curtailment Notice to the ERCOT website as soon as practicable. The quantity of DC Tie Load to be curtailed shall be the minimum required to resolve the constraint(s) after the other remediation actions described above have been taken.

(16) ERCOT may curtail DC Tie Schedules as necessary to ensure that any Entity in the ERCOT Region that is not a "public utility" as defined in the FPA, including ERCOT, does not become such a public utility.

[NPRR1034: Insert paragraph (17) below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities; and renumber accordingly:]

(17) ERCOT may curtail DC Tie Schedules on a DC Tie on a last-in-first-out basis when ERCOT determines that one or more DC Tie Schedules on that DC Tie would exceed a limit established pursuant to paragraph (1) of Section 4.4.4.4, Frequency-Based Limits on DC Tie Imports or Exports.

(17) Market Participants shall not engage in DC Tie export transactions that are reasonably expected to be uneconomic in consideration of all costs and revenues associated with the transaction, excluding Congestion Revenue Right (CRR) Auction Revenue Distribution (CARD) and CRR Balancing Account (CRRBA) allocations.

[NPRR1030: Delete paragraph (17) above upon system implementation.]

4.4.4.1 DC Tie Schedule Criteria

(1) Each DC Tie Schedule must correspond to an implemented e-Tag and include the following information:

(a) The QSE ERCOT identifier or non-ERCOT Control Area buying the energy;

(b) The QSE ERCOT identifier or non-ERCOT Control Area selling the energy;

(c) The DC Tie Settlement Point name;

(d) The quantity in MW for each 15-minute Settlement Interval of the schedule;

(e) The first and last 15-minute Settlement Intervals of the schedule; and

(f) The e-Tag name.

[NPRR999: Insert Section 4.4.4.2 below upon project implementation of the Intra-Hour Variability (iCAT) Tool:]

4.4.4.2 Management of DC Tie Schedules due to Ramp Limitations

(1) If system conditions near or in Real-Time show insufficient ramp capability to meet the sum of all DC Ties' scheduled ramp, taking into account the full ramping capability of all available Resources and preserving sufficient Physical Responsive Capability (PRC) to avoid EEA Level 1, and ERCOT determines that sufficient time exists, ERCOT may request that one or more e-Tags be resubmitted with an adjusted ramp duration that would conform with the system's ramp capability. If ERCOT determines that insufficient time exists to request resubmission of e-Tags, or that an insufficient number of e-Tags have been resubmitted to conform with the system's ramp capability, ERCOT shall curtail DC Tie Schedules on a last-in-first-out basis as necessary to conform with the system's ramp capability and shall deny any additional e-Tags that cannot be accommodated within that ramp capability during the impacted intervals.

[NPRR1034: Insert Section 4.4.4.3 below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

4.4.4.3 Frequency-Based Limits on DC Tie Imports or Exports

(1) ERCOT may establish import or export limits applicable to any DC Tie to mitigate the risk of significant frequency deviation due to the unexpected loss of that DC Tie. ERCOT shall identify the operating conditions and limits it would expect to use in a posting to the ERCOT website.

4.4.5 [RESERVED]

4.4.6 PTP Obligation Bids

(1) A Point-to-Point (PTP) Obligation bid is a bid that specifies the source and sink, a range of hours, and a maximum price that the bidder is willing to pay ("Not-to-Exceed Price").

(2) PTP Obligations that are bought in the Day-Ahead Market (DAM) must be settled based on the applicable Real-Time Settlement Point Prices.

(3) A PTP Obligation with Links to an Option is held to be reflective of the Non-Opt-In Entity's (NOIE's) PTP Option if the source and sink pairs on both the NOIE's PTP Obligation and the NOIE's PTP Option are the same, and the MWs of the NOIE's PTP Obligations are less than or equal to the number of MWs of the NOIE's PTP Option. There shall be no payment for PTP Obligations with Links to an Option acquired in the DAM.

4.4.6.1 PTP Obligation Bid Criteria

(1) A PTP Obligation bid must be submitted by a QSE and must include the following:

(a) The name of the QSE submitting the PTP Obligation bid;

(b) The source Settlement Point and the sink Settlement Point for the PTP Obligation or block of PTP Obligations being bid;

(c) NOIE peak Load forecast for the Operating Day, if the PTP Obligation bid is a PTP Obligation with Links to an Option;

(d) The first hour and the last hour for which the PTP Obligation or block of PTP Obligations is being bid;

(e) The quantity of PTP Obligations in MW for which the Not-to-Exceed Price is effective; and

(f) A dollars per MW per hour for the Not-to-Exceed Price.

[NPRR918: Replace paragraph (1) above with the following upon system implementation:]

(1) A PTP Obligation bid must be submitted by a QSE and must include the following:

(a) The name of the QSE submitting the PTP Obligation bid;

(b) The source Settlement Point and the sink Settlement Point for the PTP Obligation or block of PTP Obligations being bid;

(c) Hourly NOIE Load forecast for the Operating Day, if the PTP Obligation bid is a PTP Obligation with Links to an Option;

(d) The first hour and the last hour for which the PTP Obligation or block of PTP Obligations is being bid;

(e) The quantity of PTP Obligations in MW for which the Not-to-Exceed Price is effective; and

(f) A dollars per MW per hour for the Not-to-Exceed Price.

(2) If the PTP Obligation bid is for more than one PTP Obligation (which is one MW for one hour), the block bid must:

(a) Include the same number of PTP Obligations in each hour of the block;

(b) Be for PTP Obligations that have the same source and sink Settlement Points; and

(c) Be for contiguous hours.

(3) A PTP Obligation bid shall not contain a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points.

(4) PTP Obligation bids shall not be submitted in combination with PTP Obligation bids or with DAM Energy-Only Offer Curves and DAM Energy Bids to create the net effect of a single PTP Obligation bid containing a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points for the QSE or for any combination of QSEs within the same Counter-Party.

(5) For each NOIE or QSE representing NOIEs that designated PTP Obligations with Links to an Option, the total of each hourly MW quantity designated to be settled in Real-Time as a PTP Option may not exceed the lesser of:

(a) 110% of that NOIE’s peak Load forecast for the Operating Day; or

(b) 125% of the NOIE’s hourly Load forecast for the Operating Day.

[NPRR918: Replace paragraph (5) above with the following upon system implementation:]

(5) For each QSE representing NOIEs that designated PTP Obligations with Links to an Option, the total of each hourly MW quantity designated to be settled in Real-Time as a PTP Option may not exceed the lesser of:

(a) 110% of that NOIE's peak Load forecast for the Operating Day; or

(b) 125% of the NOIE's Load forecast for the Operating Hour.

(6) PTP Obligations with Links to an Option shall be used for delivery of energy to a NOIE Load or a valid combination of Settlement Points that physically or contractually mitigates risk in supplying the NOIE Load. This applies to each NOIE or QSE representing NOIEs.

(7) In addition to the criteria above for other PTP Obligations, PTP Obligations with Links to an Option must further include the following:

(a) The name of the CRR Account Holder that owns the CRRs being offered; and

(b) The unique identifier for each CRR being offered.

(8) For PTP Obligations with Links to an Option, the CRR Account Holder for whom the PTP Obligations with Links to an Option are being submitted must be shown in the ERCOT CRR registration system as the owner of the CRRs being linked to the PTP Obligation.

(9) The minimum amount for each PTP Obligation with Links to an Option is one-tenth of one MW. The minimum amount for each PTP Obligation bid is one MW.

4.4.6.2 PTP Obligation Bid Validation

(1) A validated PTP Obligation bid is a bid that ERCOT has determined meets the criteria listed in Section 4.4.6.1, PTP Obligation Bid Criteria, with the exception of paragraphs (3), (4), (5) and (6). Bids that do not meet the criteria in paragraph (3) of Section 4.4.6.1 will not be awarded in the DAM.

[NPRR918: Replace paragraph (1) above with the following upon system implementation:]

(1) A validated PTP Obligation bid is a bid that ERCOT has determined meets the criteria listed in Section 4.4.6.1, PTP Obligation Bid Criteria, with the exception of paragraphs (3), (4), and (6). Bids that do not meet the criteria in paragraph (3) of Section 4.4.6.1 will not be awarded in the DAM.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any QSE submitting a PTP Obligation bid to view its valid PTP Obligation bid.

(3) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its PTP Obligation bids that are invalid. The QSE may correct and resubmit any invalid PTP Obligation bid within the appropriate market timeline.

4.4.6.3 PTP Obligations with Links to an Option DAM Award Eligibility

(1) A bid for a PTP Obligation with Links to an Option will not be considered eligible for award for an Operating Hour if it sources at a Resource Node where the Generation Resource has a COP Resource Status of:

(a) OUT for an Operating Hour; or

(b) OFF for an Operating Hour; and

(i) The QSE representing the Resources has not submitted a valid Three-Part Supply Offer or Ancillary Service Offer to be considered by the DAM; and

(ii) The QSE representing the Resource has not submitted a valid Energy Only Offer at any Resource Node associated with the Resource.

(2) Where more than one Generation Resource is associated with a Resource Node, ERCOT will consider a PTP Obligation with Links to an Option bid eligible for award unless all Generation Resources associated with the Resource Node do not satisfy the COP Resource Status requirements in paragraph (1) above during the Operating Hour.

(3) In order for ERCOT to award a bid for a PTP Obligation with Links to an Option under this section for an upcoming year, by October 1 of the prior year a NOIE must have provided ERCOT with an attestation that the Generation Resource for the Resource Node where the bid is sourced is owned or controlled by the NOIE, or has a contractual commitment for capacity and/or energy with the NOIE. The attestation must be executed by an officer or executive with authority to bind the NOIE, and submitted to ERCOT. ERCOT shall rely exclusively on the attestation provided by a NOIE in determining eligibility for bid awards under this section. ERCOT shall issue a Market Notice by September 1 of each year reminding NOIEs of the October 1 deadline for submitting attestations for the upcoming year.

4.4.7 Ancillary Service Supplied and Traded

4.4.7.1 Self-Arranged Ancillary Service Quantities

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the Ancillary Service Obligation allocated to it by ERCOT. QSEs may not self-arrange Regulation

Service amounts that include Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) quantities. In addition, a QSE may self-arrange up to 100 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 100 MW of Non-Spinning Reserve (Non-Spin) in excess of its corresponding Ancillary Service Obligation, provided that the amount self-arranged from the QSE's Resources for a given Ancillary Service shall not exceed the amount of the QSE's Ancillary Services Obligation for that Ancillary Service. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation. Any Self-Arranged Ancillary Service Quantities in excess of a QSE's Ancillary Service Obligation will be considered to be offered in the DAM or Supplemental Ancillary Services Market (SASM), as applicable, for $0/MWh.

[NPRR1091: Replace paragraph (1) above with the following upon system implementation:]

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the Ancillary Service Obligation allocated to it by ERCOT. QSEs may not self-arrange Regulation Service amounts that include Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) quantities. In addition, a QSE may self-arrange up to 150 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 300 MW of Non-Spinning Reserve (Non-Spin) in excess of its corresponding Ancillary Service Obligation, provided that the amount self-arranged from the QSE's Resources for a given Ancillary Service shall not exceed the amount of the QSE's Ancillary Services Obligation for that Ancillary Service. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation. Any Self-Arranged Ancillary Service Quantities in excess of a QSE's Ancillary Service Obligation will be considered to be offered in the DAM or Supplemental Ancillary Services Market (SASM), as applicable, for $0/MWh.

[NPRR863 and NPRR1008: Replace applicable portions of paragraph (1) above with the following upon system implementation or upon system implementation of the Real-Time Co-Optimization (RTC) project, respectively:]

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the advisory Ancillary Service Obligation allocated to it by ERCOT, subject to the QSE's share of system-wide limits as established by Section 3.16, Standards for Determining Ancillary Service Quantities. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its final Ancillary Service Obligation; ERCOT shall pay the QSE the respective Day-Ahead Ancillary Service price for any Self-

Arranged Ancillary Service Quantities that exceed a QSE's final Ancillary Service Obligation.

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, needs to be obtained through the DAM.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, remains to be obtained based on DAM offers and associated Ancillary Service Demand Curves (ASDCs).

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities unless ERCOT opens a SASM.

[NPRR1008: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities.

(4) Before 1430 in the Day-Ahead, all Self-Arranged Ancillary Service Quantities must be represented by physical capacity, either by Generation Resources or Load Resources, or backed by Ancillary Service Trades.

(5) The QSE may self-arrange Reg-Up, Reg-Down, RRS, and Non-Spin.

[NPRR863: Replace paragraph (5) above with the following upon system implementation:]

(5) The QSE may self-arrange Reg-Up, Reg-Down, ECRS, RRS, and Non-Spin.

(6) The QSE may self-arrange Ancillary Services from one or more Resources it represents and/or through an Ancillary Service Trade.

(7) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a SASM notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than 100 MWs of RRS, 25 MWs of Reg-Up, 25 MWs of Reg-Down, and 100 MWs of Non-Spin greater than the additional Ancillary Service

amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT.

[NPRR863: Replace paragraph (7) above with the following upon system implementation:]

(7) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a SASM notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than 100 MW of ECRS, 100 MW of RRS, 25 MW of Reg-Up, 25 MW of Reg-Down, and 50 MW of Non-Spin greater than the additional Ancillary Service amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT.

(8) If a QSE does not self-arrange all of its Ancillary Service Obligation, ERCOT shall procure the remaining amount of that QSE's Ancillary Service Obligation.

[NPRR1008: Replace paragraphs (7) and (8) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

(7) A QSE shall not submit Ancillary Services trades that result in the QSE's purchased quantities of Ancillary Services exceeding the QSE's Self-Arranged Ancillary Service Quantities.

(a) At 1430 in the Day-Ahead, ERCOT shall post a report on the MIS Certified Area to notify the QSE if there is an overage in the QSE's purchased quantities of Ancillary Services in violation of the above limitation.

(b) If the QSE has such an overage as of the end of the Adjustment Period, that QSE will be charged for any quantity that exceeds their Self-Arranged Ancillary Service Quantities per Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge.

(9) For self-arranged RRS, the QSE shall indicate the quantity of the service that is provided from:

(a) Resources providing Primary Frequency Response;

(b) Load Resources controlled by high-set under-frequency relays; and

(c) Fast Frequency Response (FFR) Resources.

[NPRR1015: Insert paragraph (10) below upon system implementation of NPRR863:]

(10) For self-arranged ECRS, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched and those that are SCED-dispatchable.

4.4.7.1.1 Negative Self-Arranged Ancillary Service Quantities

(1) A QSE may submit a negative Self-Arranged Ancillary Service Quantity in the DAM. ERCOT shall procure all negative Self-Arranged Ancillary Service Quantities submitted by a QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) A QSE may submit a negative Self-Arranged Ancillary Service Quantity in the DAM. ERCOT shall procure all negative Self-Arranged Ancillary Service Quantities submitted by a QSE. Such negative Self-Arranged Ancillary Service Quantities will be considered by DAM to be equivalent to a bid to buy Ancillary Services at the highest price on each respective ASDC.

(2) Procurements of negative Self-Arranged Ancillary Service Quantities by ERCOT shall be settled in the same manner as Ancillary Service Obligations that are not self-arranged and according to the charges defined in Section 4.6.4.2, Charges for Ancillary Services Procurement in the DAM, and Section 6.7, Real-Time Settlement Calculations for the Ancillary Services.

(3) A QSE may not submit a negative Self-Arranged Ancillary Service Quantity in the DAM that is less than -500 MW per Ancillary Service. For negative self-arranged RRS, the QSE shall not specify FFR Resources, Controllable Load Resources and Load Resources controlled by high-set under-frequency relays. For compliance purposes, a QSE may not submit a negative Self-Arranged Ancillary Service Quantity in the DAM that is greater in magnitude than the absolute value of the net sales of its Ancillary Service Trades per Ancillary Service.

[NPRR863: Replace paragraph (3) above with the following upon system implementation:]

(3) A QSE may not submit a negative Self-Arranged Ancillary Service Quantity in the DAM that is less than -500 MW per Ancillary Service. For negative self-arranged RRS and ECRS, the QSE shall not specify FFR Resources, Controllable Load Resources, and Load Resources controlled by high-set under-frequency relays. For compliance purposes, a QSE may not submit a negative Self-Arranged Ancillary

Service Quantity in the DAM that is greater in magnitude than the absolute value of the net sales of its Ancillary Service Trades per Ancillary Service.

4.4.7.2 Ancillary Service Offers

(1) By 1000 in the Day-Ahead, a QSE may submit Generation Resource-specific Ancillary Service Offers to ERCOT for the DAM and may offer the same Generation Resource capacity for any or all of the Ancillary Service products simultaneously with any Energy Offer Curves from that Generation Resource in the DAM. A QSE may also submit Ancillary Service Offers in a SASM. Offers of more than one Ancillary Service product from one Generation Resource may be inclusive or exclusive of each other and of any Energy Offer Curves, as specified according to a procedure developed by ERCOT.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(1) By 1000 in the Day-Ahead, a QSE may submit Resource-Specific Ancillary Service Offers from Generation Resources and ESRs to ERCOT for the DAM and may offer the same Generation Resource or ESR capacity for any or all of the Ancillary Service products simultaneously with any Energy Offer Curves from that Generation Resource or Energy Bid/Offer Curves from that ESR in the DAM. Offers of more than one Ancillary Service product from one Generation Resource may be inclusive or exclusive of each other and of any Energy Offer Curves, as specified according to a procedure developed by ERCOT. Offers of more than one Ancillary Service product from one ESR may be inclusive or exclusive of each other, as specified according to a procedure developed by ERCOT.

(2) By 1000 in the Day-Ahead, a QSE may submit Load Resource-specific Ancillary Service Offers for Regulation Service, Non-Spin and RRS to ERCOT and may offer the same Load Resource capacity for any or all of those Ancillary Service products simultaneously. Offers of more than one Ancillary Service product from one Load Resource may be inclusive or exclusive of each other, as specified according to a procedure developed by ERCOT.

[NPRR863, NPRR1008, and NPRR1014: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR863 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008:]

(2) By 1000 in the Day-Ahead, a QSE may submit Load Resource-Specific Ancillary Service Offers for Regulation Service, Non-Spin, RRS, and ECRS to ERCOT and may offer the same Load Resource capacity for any or all of those Ancillary Service

products simultaneously. Offers of more than one Ancillary Service product from one Load Resource may be inclusive or exclusive of each other, as specified according to a procedure developed by ERCOT.

(3) By 1000 in the Day-Ahead, a QSE may submit Resource-specific Ancillary Service Offers to ERCOT for FFR Resources, and may offer the same capacity for any or all of the Ancillary Service products simultaneously with any Energy Offer Curves from that Resource in the DAM. A QSE may also submit Ancillary Service Offers in a SASM. Offers of more than one Ancillary Service product may be inclusive or exclusive of each other and of any Energy Offer Curves, as specified according to a procedure developed by ERCOT.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(3) By 1000 in the Day-Ahead, a QSE may submit Resource-Specific Ancillary Service Offers to ERCOT for FFR Resources, and may offer the same capacity for any or all of the Ancillary Service products simultaneously with any Energy Offer Curves from that Resource in the DAM. Offers of more than one Ancillary Service product may be inclusive or exclusive of each other and of any Energy Offer Curves, as specified according to a procedure developed by ERCOT.

[NPRR1008 and NPRR1014: Insert applicable portions of paragraph (4) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly:]

(4) By 1000 in the Day-Ahead, a QSE may submit an Ancillary Service Only Offer to ERCOT for the DAM. An individual Ancillary Service Only Offer must be exclusive to a single Ancillary Service product. For purposes of Ancillary Service sub-category limitations and validations, an Ancillary Service Only Offer for RRS will be treated as if it was an offer for RRS from an On-Line Generation Resource. Likewise, an Ancillary Service Only Offer for ECRS will be treated as if it was an offer for ECRS from an On-Line Generation Resource.

(4) Ancillary Service Offers remain active for the offered period until:

(a) Selected by ERCOT;

(b) Automatically inactivated by the software at the offer expiration time specified by the QSE when the offer is submitted; or

(c) Withdrawn by the QSE, but a withdrawal is not effective if the deadline for submitting offers has already passed.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(4) Ancillary Service Offers remain active for the offered period unless the offer is:

(a) Effective after DAM and is higher than the Real-Time System-Wide Offer Cap (RTSWCAP);

(b) Automatically inactivated by the software at the offer expiration time specified by the QSE when the offer is submitted; or

(c) Withdrawn by the QSE, but a withdrawal is not effective if the deadline for submitting offers has already passed.

(5) A Load Resource that is not a Controllable Load Resource may specify whether its Ancillary Service Offer for RRS or Non-Spin may only be procured by ERCOT as a block.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(5) A Load Resource that is not a Controllable Load Resource may specify whether its Resource-Specific Ancillary Service Offer for RRS or Non-Spin may only be procured by ERCOT as a block.

[NPRR863 or NPRR1014: Insert applicable portions of paragraph (6) below upon system implementation and renumber accordingly:]

(6) A Load Resource that is not a Controllable Load Resource may specify whether its Resource-Specific Ancillary Service Offer for ECRS may only be procured by ERCOT as a block.

(6) A QSE that submits an On-Line Ancillary Service Offer without also submitting a Three-Part Supply Offer for the DAM for any given hour will be considered by the DAM to be self-committed for that hour, as long as an Ancillary Service Offer for Off-Line Non-Spin was not also submitted for that hour. When the DAM considers a self-committed offer for clearing, the Resource constraints identified in paragraph (4)(c)(ii) of Section 4.5.1,

DAM Clearing Process, other than HSL, are ignored. A Combined Cycle Generation Resource will be considered by the DAM to be self-committed based on an On-Line Ancillary Service Offer submittal if:

(a) Its QSE submits an On-Line Ancillary Service Offer without also submitting a Three-Part Supply Offer for the DAM for any Combined Cycle Generation Resource within the Combined Cycle Train for that hour;

(b) No Ancillary Service Offer for Off-Line Non-Spin for any Combined Cycle Generation Resource within the Combined Cycle Train is submitted for that hour; and

(c) No On-Line Ancillary Service Offer for any other Combined Cycle Generation Resource within the Combined Cycled Train is submitted for that hour.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(6) A QSE that submits an On-Line Resource-Specific Ancillary Service Offer without also submitting a Three-Part Supply Offer for the DAM for any given hour will be considered by the DAM to be self-committed for that hour, as long as a Resource-Specific Ancillary Service Offer for Off-Line Non-Spin was not also submitted for that hour. A QSE that submits an On-Line ESR-specific Ancillary Service Offer or Energy Bid/Offer Curve for the DAM will be considered to be On-Line. A QSE may not submit an Off-Line Ancillary Service Offer for an ESR. When the DAM considers a self-committed offer for clearing, the Resource constraints identified in paragraph (4)(c)(ii) of Section 4.5.1, DAM Clearing Process, other than HSL, are ignored; however, for an ESR, the DAM will consider LSL and HSL. A Combined Cycle Generation Resource will be considered by the DAM to be self-committed based on an On-Line Resource-Specific Ancillary Service Offer submittal if:

(a) Its QSE submits an On-Line Resource-Specific Ancillary Service Offer without also submitting a Three-Part Supply Offer for the DAM for any Combined Cycle Generation Resource within the Combined Cycle Train for that hour;

(b) No Resource-Specific Ancillary Service Offer for Off-Line Non-Spin for any Combined Cycle Generation Resource within the Combined Cycle Train is submitted for that hour; and

(c) No On-Line Resource-Specific Ancillary Service Offer for any other Combined Cycle Generation Resource within the Combined Cycled Train is submitted for that hour.

(7) ERCOT will attempt to procure the quantity from its Ancillary Service Plan from Resource-Specific Ancillary Service Offers as well as Ancillary Service Only Offers against respective ASDCs.

4.4.7.2.1 Ancillary Service Offer Criteria

(1) Each Ancillary Service Offer must be submitted by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) The quantity in MW and Ancillary Service type from that Resource for this specific offer and the specific quantity in MW and Ancillary Service type of any other Ancillary Service offered from this same capacity;

(d) An Ancillary Service Offer linked to a Three-Part Supply Offer from a Resource designated to be Off-Line for the offer period in its COP may only be struck if the Three-Part Supply Offer is struck. The total capacity struck must be within limits as defined in item (4)(c)(iii) of Section 4.5.1, DAM Clearing Process;

(e) An Ancillary Service Offer linked to other Ancillary Service Offers or an Energy Offer Curve from a Resource designated to be On-Line for the offer period in its COP may only be struck if the total capacity struck is within limits as defined in item (4)(c)(iii) of Section 4.5.1;

(f) The first and last hour of the offer;

(g) A fixed quantity block, or variable quantity block indicator for the offer:

(i) If a fixed quantity block, not to exceed 150 MW, which may only be offered by a Load Resource that is not a Controllable Load Resource and that is offering to provide RRS or Non-Spin, and which may clear at a Market Clearing Price for Capacity (MCPC) below the Ancillary Service Offer price for that block, the single price (in $/MW) and single quantity (in MW) for all hours offered in that block; or

(ii) If a variable quantity block, which may be offered by a Generation Resource or a Load Resource, the single price (in $/MW) and single "up to" quantity (in MW) contingent on the purchase of all hours offered in that block; and

(h) The expiration time and date of the offer.

(2) A valid Ancillary Service Offer in the DAM must be received before 1000 for the effective DAM. A valid Ancillary Service Offer in an SASM must be received before the applicable deadline for that SASM.

(3) No Ancillary Service Offer price may exceed the System-Wide Offer Cap (SWCAP) (in $/MW). No Ancillary Service Offer price may be less than $0 per MW.

(4) The minimum amount per Resource for each Ancillary Service product that may be offered is one-tenth (0.1) MW.

(5) A Resource may offer more than one Ancillary Service.

(6) A Load Resource that is not a Controllable Load Resource, may simultaneously offer RRS and Non-Spin in a DAM or SASM and be awarded RRS and Non-Spin for the same Operating Hour but will not be allowed to provide RRS and Non-Spin on the same Load Resource simultaneously in Real-Time.

(7) Offers for Load Resources may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements.

(8) A Load Resource that is qualified to perform as a Controllable Load Resource may not offer to provide Ancillary Services as a Controllable Load Resource and a Load Resource controlled by high-set under-frequency relay simultaneously behind a common breaker.

[NPRR863, NPRR1008, and NPRR1014: Replace applicable portions of Section 4.4.7.2.1 above with the following upon system implementation for NPRR863 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008:]

4.4.7.2.1 Resource-Specific Ancillary Service Offer Criteria

(1) Each Resource-Specific Ancillary Service Offer must be submitted by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) The quantity in MW and Ancillary Service type from that Resource for this specific offer and the specific quantity in MW and Ancillary Service type of any other Ancillary Service offered from this same capacity;

(d) A Resource-Specific Ancillary Service Offer linked to a Three-Part Supply Offer from a Resource designated to be Off-Line for the offer period in its COP may only be struck if the Three-Part Supply Offer is struck. The total capacity struck must be within limits as defined in item (4)(c)(iii) of Section 4.5.1, DAM Clearing Process;

(e) A Resource-Specific Ancillary Service Offer linked to other Resource-Specific Ancillary Service Offers or an Energy Offer Curve or Energy Bid/Offer Curve from a Resource designated to be On-Line for the offer period in its COP may only be struck if the total capacity struck is within limits as defined in item (4)(c)(iii) of Section 4.5.1;

(f) The first and last hour of the offer;

(g) A fixed quantity block or variable quantity block indicator for the offer:

(i) If a fixed quantity block, not to exceed 150 MW, which may only be offered by a Load Resource that is not a Controllable Load Resource and that is offering to provide RRS, ECRS, or Non-Spin, and which may clear at a Market Clearing Price for Capacity (MCPC) below the Resource-Specific Ancillary Service Offer price for that block, the single price (in $/MW) and single quantity (in MW) for all hours offered in that block. This fixed quantity block indicator will only be considered in the DAM and will be ignored for awarding of Ancillary Services in the Real-Time Market (RTM); or

(ii) If a variable quantity block, which may be offered by a Generation Resource, an ESR, or a Load Resource, the single price (in $/MW) and single "up to" quantity (in MW) contingent on the purchase of all hours offered in that block. This variable quantity block indicator will only be considered in the DAM and will be ignored for awarding of Ancillary Services in the RTM; and

(h) The expiration time and date of the offer.

(2) A valid Resource-Specific Ancillary Service Offer in the DAM must be received before 1000 for the effective DAM.

(3) No Resource-Specific Ancillary Service Offer received before 1000 in the Day-Ahead may contain a price exceeding the Day-Ahead System-Wide Offer Cap (DASWCAP) (in $/MW). No Resource-Specific Ancillary Service Offer received after 1430 in the Day-Ahead may contain a price exceeding the Real-Time System-Wide Offer Cap (RTSWCAP) (in $/MW). No Ancillary Service Offer price may be less than $0 per MW.

(4) The minimum amount per Resource for each Ancillary Service product that may be offered is one-tenth (0.1) MW.

(5) A Resource may offer more than one Ancillary Service.

(6) A Load Resource, that is not a Controllable Load Resource, may simultaneously offer RRS, ECRS, and Non-Spin in a DAM and be awarded RRS, ECRS, and Non-Spin for the same Operating Hour in the DAM, but will not be awarded Non-Spin and RRS on the same Load Resource simultaneously in Real-Time.

(7) Offers for Load Resources may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements.

(8) A Load Resource that is qualified to perform as a Controllable Load Resource may not offer to provide Ancillary Services as a Controllable Load Resource and a Load Resource controlled by high-set under-frequency relay simultaneously behind a common breaker.

4.4.7.2.2 Ancillary Service Offer Validation

(1) A valid Ancillary Service Offer is one that ERCOT has determined meets the criteria listed in Section 4.4.7.2.1, Ancillary Service Offer Criteria.

(2) ERCOT shall continuously validate Ancillary Service Offers and continuously display on the MIS Certified Area information that allows any QSE named in an Ancillary Service Offer to view its confirmed Ancillary Service Offers.

(3) ERCOT shall notify the QSE submitting an Ancillary Service Offer if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the offer within the appropriate market timeline.

[NPRR1008: Replace Section 4.4.7.2.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.4.7.2.2 Resource-Specific Ancillary Service Offer Validation

(1) A valid Resource-Specific Ancillary Service Offer is one that ERCOT has determined meets the criteria listed in Section 4.4.7.2.1, Resource-Specific Ancillary Service Offer Criteria.

(2) ERCOT shall continuously validate Resource-Specific Ancillary Service Offers and continuously display on the MIS Certified Area information that allows any QSE named in a Resource-Specific Ancillary Service Offer to view its confirmed Resource-Specific Ancillary Service Offers.

(3) ERCOT shall notify the QSE submitting a Resource-Specific Ancillary Service Offer if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the offer within the appropriate market timeline.

[NPRR1008: Insert Section 4.4.7.2.3 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.4.7.2.3 Ancillary Service Only Offer Criteria

(1) Each Ancillary Service Only Offer must be submitted by a QSE and must include the following information:

(a) The selling QSE;

(b) The quantity in MW and Ancillary Service type;

(c) The first and last Operating Hour of the offer;

(2) A valid Ancillary Service Only Offer in the DAM must be received before 1000 in the Day-Ahead.

(3) No Ancillary Service Only Offer price may exceed the DASWCAP (in $/MW). No Ancillary Service Only Offer price may be less than $0 per MW.

(4) The minimum amount that may be offered is one-tenth (0.1) MW.

[NPRR1008: Insert Section 4.4.7.2.4 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.4.7.2.4 Ancillary Service Only Offer Validation

(1) A valid Ancillary Service Only Offer is one that ERCOT determines meets the criteria listed in Section 4.4.7.2.3, Ancillary Service Only Offer Criteria.

(2) ERCOT shall continuously validate Ancillary Service Only Offers and continuously display on the MIS Certified Area information that allows any QSE named in an Ancillary Service Only Offer to view its confirmed Ancillary Service Only Offers.

(3) ERCOT will notify the QSE submitting an Ancillary Service Only Offer using the MIS Certified Area if the offer was rejected or was considered invalid for any reason. The QSE may resubmit the offer if the time for receiving offers has not elapsed.

4.4.7.3 Ancillary Service Trades

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity or purchase Ancillary Services in the Real-Time Market (RTM) between a buyer and a seller.

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

(3) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Ancillary Service Trades that are invalid Ancillary Service Trades. The QSE may correct and resubmit any invalid Ancillary Service Trade, but the reporting time of the trade is determined by when the validated Ancillary Service Trade was submitted and not when the original invalid Ancillary Service Trade was submitted.

[NPRR863, NPRR1008, and NPRR1015: Insert applicable portions of paragraphs (4)-(6) below upon system implementation of NPRR863 for NPRR863 and NPRR1015; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; and renumber accordingly:]

(4) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a Generation Resource, may transfer that portion of its Ancillary Service Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by a Generation Resource.

(5) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz, may transfer that portion of its Ancillary Service

Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by either:

(a) A Generation Resource; or

(b) A Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz.

(6) The table below shows the ECRS trades that are allowed for each type of original responsibility:

	Allowable ECRS Ancillary Service Trades	
Original Responsibility	**SCED-dispatchable ECRS**	**Manually dispatched ECRS**
SCED-dispatchable ECRS	Yes	No
Manually dispatched ECRS	Yes	Yes

(4) The table below shows the RRS trades that are allowed for each type of original responsibility:

	Allowable RRS Ancillary Service Trades		
Original Responsibility	**Resource providing Primary Frequency Response**	**Resource providing FFR triggered at 59.85 Hz**	**Load Resource triggered at 59.7 Hz**
Resource providing Primary Frequency Response	Yes	No	No
Resource providing FFR triggered at 59.85 Hz	Yes	Yes	Yes
Load Resource triggered at 59.7 Hz	Yes	No	Yes

(5) The table below shows the Non-Spin trades that are allowed for each type of original responsibility:

Allowable Non-Spin Ancillary Service Trades		
Original Responsibility	**Generation Resource or Controllable Load Resource**	**Load Resource other than a Controllable Load Resource**
Generation Resource or Controllable Load Resource	Yes	No
Load Resource other than a Controllable Load Resource	Yes	Yes

[NPRR1136 Insert paragraph (6) below upon system implementation:]

(6) The table below shows the Regulation Service trades that are allowed for each type of original responsibility. The same limitations apply separately to both Reg-Up and Reg-Down:

	Allowable Regulation Ancillary Service Trades	
Original Responsibility	**Regulation Service that is not FRRS**	**FRRS**
Regulation Service that is not Fast Responding Regulation Service (FRRS)	Yes	No
FRRS	Yes	Yes

4.4.7.3.1 Ancillary Service Trade Criteria

(1) Each Ancillary Service Trade must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The selling QSE;

(c) The type of Ancillary Service;

(d) The quantity in MW; and

(e) The first and last hours of the trade.

(f) For RRS, the QSE shall indicate the quantity of the service that is provided from:

(i) Resources providing Primary Frequency Response;

(ii) FFR Resources; and

(iii) Load Resources controlled by high-set under-frequency relays.

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

(f) For RRS, the QSE shall indicate the quantity of the service that is provided from:

(i) Resources capable of providing Primary Frequency Response;

(ii) ESRs and Load Resources providing FFR; and

(iii) Load Resources controlled by high-set under-frequency relays.

[NPRR1015: Insert paragraph (2) below upon system implementation of NPRR863 and renumber accordingly:]

(2) For ECRS, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched and those that are SCED-dispatchable.

(2) An Ancillary Service Trade must be confirmed by both the buying QSE and selling QSE to be considered valid and to be used in an ERCOT process.

4.4.7.3.2 Ancillary Service Trade Validation

(1) A valid Ancillary Service Trade is an Ancillary Service Trade that ERCOT has determined meets the criteria listed in Section 4.4.7.3.1, Ancillary Service Trade Criteria. Only one confirmed Ancillary Service Trade is allowed for the same buying and selling QSEs for each type of Ancillary Service for each hour.

(2) When an Ancillary Service Trade is reported to ERCOT, ERCOT shall notify both the buying and selling QSEs by using the Messaging System if available and the MIS Certified Area.

(3) ERCOT shall continuously validate Ancillary Service Trades and continuously display on the MIS Certified Area information that allows any QSE named in an Ancillary Service Trade to view its confirmed and unconfirmed Ancillary Service Trades. ERCOT shall also post to the MIS Certified Area any unconfirmed Ancillary Service Trades for QSEs

on an hourly basis for all remaining hours of the current Operating Day and all hours of the next Operating Day.

(4) The QSE that first reports the Ancillary Service Trade to ERCOT is deemed to have confirmed the Ancillary Service Trade unless it subsequently affirmatively rejects it. The QSE that first reports an Ancillary Service Trade may reject, edit, or delete an Ancillary Service Trade that its counterpart has not confirmed. The counterpart is deemed to have confirmed the Ancillary Service Trade when it submits an identical Ancillary Service Trade. After both the buyer and seller have confirmed an Ancillary Service Trade, either party may reject it at any time, but the rejection is effective only for any ERCOT process for which the deadline for reporting Ancillary Service Trades has not yet passed.

4.4.7.4 Ancillary Service Supply Responsibility

(1) A QSE's Ancillary Service Supply Responsibility is the net amount of Ancillary Service capacity that the QSE is obligated to deliver to ERCOT, by hour and service type, from Resources represented by the QSE. The Ancillary Service Supply Responsibility is the difference in MW, by hour and service type, between the amounts specified in items (a) and (b) defined as follows:

(a) The sum of:

(i) The QSE's Self-Arranged Ancillary Service Quantity; plus

(ii) The total (in MW) of Ancillary Service Trades for which the QSE is the seller; plus

(iii) Awards to the QSE of Ancillary Service Offers in the DAM; plus

(iv) Awards to the QSE of Ancillary Service Offers in the SASM; plus

(v) RUC-committed Ancillary Service quantities to the QSE from its Resources committed by the RUC process to provide Ancillary Service; and

(b) The sum of:

(i) The total Ancillary Service Trades for which the QSE is the buyer; plus

(ii) The total Ancillary Service identified as to the QSE's failure to provide as described in Section 6.4.9.1.3, Replacement of Ancillary Service Due to Failure to Provide; plus

(iii) The total Ancillary Service identified as the QSE's infeasible Ancillary Service, as described in Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints; plus

(iv) The total Ancillary Service identified as the QSE's reconfiguration amount as described in Section 6.4.9.2, Supplemental Ancillary Services Market.

(2) A QSE may only use a RUC-committed Resource during that Resource's RUC-Committed Interval to meet the QSE's Ancillary Service Supply Responsibility if the Resource has been committed by the RUC process to provide Ancillary Service. The QSE shall only provide from the RUC-committed Resource the exact amount and type of Ancillary Service for which it was committed by RUC.

(3) By 1430 in the Day-Ahead, the QSE must notify ERCOT, in the QSE's COP, which Resources represented by the QSE will provide the Ancillary Service capacity necessary to meet the QSE's Ancillary Service Supply Responsibility, specified by Resource, hour, and service type. The DAM Ancillary Service awards are Resource-specific; the QSE must include those DAM awards in its COP, and the QSE may not change that Resource-specific DAM award information until after 1600 under the conditions set out in Section 3.9, Current Operating Plan (COP).

(4) Section 6.4.9.1.3 specifies what happens if the QSE fails on its Ancillary Service Supply Responsibility.

[NPRR1008: Delete Section 4.4.7.4 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

4.4.8 RMR Offers

(1) ERCOT shall decide, in its sole discretion, to commit a Reliability Must-Run (RMR) Unit using the DRUC or HRUC process only when it has determined that the RMR Unit is likely to be needed in Real-Time for reliability reasons, taking into consideration whether SCED will solve transmission constraints without the RMR Resource, contractual constraints on the Resource, and any other adverse effects on the RMR Unit that may occur as the result of the dispatch of the RMR Resource.

(a) If ERCOT has determined that an RMR Unit will be needed in Real-Time to resolve a transmission constraint, then ERCOT shall manually commit the Resource for the capacity required to resolve the transmission constraint using the DRUC or HRUC process.

(b) ERCOT may submit Energy Offer Curves at the SWCAP in $/MWh on behalf of RMR Units committed in the DRUC or HRUC, and subsequently available for Dispatch by SCED, unless ERCOT declares a Market Suspension, in which case no Energy Offer Curves will be submitted, and ERCOT may, at its discretion, Dispatch RMR Units to restore the ERCOT Transmission Grid.

[NPRR1008: Replace paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(b) ERCOT may submit Energy Offer Curves at the effective Value of Lost Load (VOLL) in $/MWh on behalf of RMR Units committed in the DRUC or HRUC, and subsequently available for Dispatch by SCED, unless ERCOT declares a Market Suspension, in which case no Energy Offer Curves will be submitted, and ERCOT may, at its discretion, Dispatch RMR Units to restore the ERCOT Transmission Grid.

(c) RMR offers shall be treated as if they were Resource offers for purposes of posting under Section 3.2.5, Publication of Resource and Load Information.

4.4.9 Energy Offers and Bids

4.4.9.1 Three-Part Supply Offers

(1) A Three-Part Supply Offer consists of a Startup Offer, a Minimum-Energy Offer, and an Energy Offer Curve. ERCOT must validate each Startup Offer, Minimum-Energy Offer, and Energy Offer Curve before it can be used in any ERCOT process.

(2) The DAM uses all three parts of the Three-Part Supply Offer and also uses Energy Offer Curves submitted without a Startup Offer and without a Minimum-Energy Offer. The RUC only uses the Startup Offer and the Minimum-Energy Offer components for determining RUC commitments, but the Energy Offer Curve may be used in Settlement to claw back some or all of a RUC-committed Resource’s energy payments. The Energy Offer Curve may also be used by SCED in Real-Time Operations.

(3) A QSE may submit an Energy Offer Curve without also submitting a Startup Offer and a Minimum-Energy Offer for the DAM and during the Adjustment Period, but only Three-Part Supply Offers are used in the RUC process. A QSE that submits an Energy Offer Curve without also submitting a Startup Offer and a Minimum-Energy Offer is considered not to be offering the Resource into the RUC, but that does not prevent the Resource from being committed in the RUC process like any other Resource that does not submit an offer in the RUC.

(a) A QSE that submits an Energy Offer Curve without a Startup Offer and a Minimum-Energy Offer for the DAM for any given hour will be considered by the DAM to be self-committed for that hour, as long as an Ancillary Service Offer for Off-Line Non-Spin Service was not also submitted for that hour.

(b) A Combined Cycle Generation Resource will be considered by the DAM to be self-committed if:

(i) Its QSE submits an Energy Offer Curve without a Startup Offer and a Minimum-Energy Offer for the DAM for that Combined Cycle Generation Resource and no other Combined Cycle Generation Resource within the Combined Cycle Train; and

(ii) Its QSE submits no Ancillary Service Offer for Off-Line Non-Spin for any Combined Cycle Generation Resource within the Combined Cycle Train.

(c) When the DAM considers a self-committed offer for clearing, the Resource constraints identified in paragraph (4)(c)(ii) of Section 4.5.1, DAM Clearing Process, other than HSL, are ignored.

(4) For any hours in which the Resource is not RUC-committed, ERCOT shall consider all Three-Part Supply Offers in the RUC process until:

(a) The QSE withdraws the offer; or

(b) The offer expires by its terms.

4.4.9.2 Startup Offer and Minimum-Energy Offer

(1) The Startup Offer component represents all costs incurred by a Generation Resource in starting up and reaching its LSL. The Minimum-Energy Offer component represents a proxy for the costs incurred by a Resource in producing energy at the Resource’s LSL.

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

(1) The Startup Offer component represents all costs incurred by a Generation Resource in starting up and reaching its LSL. The Minimum-Energy Offer component represents a proxy for the costs incurred by a Resource in producing energy at the Resource’s LSL. Startup Offers and Minimum-Energy Offers are not applicable to ESRs.

4.4.9.2.1 Startup Offer and Minimum-Energy Offer Criteria

(1) Each Startup Offer and Minimum-Energy Offer must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) The Resource’s hot, intermediate, and cold Startup Offer in dollars;

(d) The Resource’s Minimum-Energy Offer in dollars per MWh;

(e) The first and last hour of the Startup and Minimum-Energy Offers

(f) The expiration time and date of the offer;

(g) Percentage of the Fuel Index Price (FIP) to the extent that the startup and minimum energy will be supplied by gas to determine the offer cap; and

(h) Percentage of the Fuel Oil Price (FOP) to the extent that the startup and minimum energy will be supplied by oil to determine the offer cap.

(2) Valid Startup Offers and Minimum-Energy Offers (which must be part of a Three-Part Supply Offer) must be received before 1000 for the effective DAM and DRUC.

(3) A QSE may update and submit a Startup Offer and/or Minimum-Energy Offer for a Resource during the Adjustment Period for any hours in which the Resource is not DAM- or RUC-committed before the offer is updated or submitted.

(4) The Resource's Startup Offer must not be greater than 200% of the Resource Category Generic Startup Cost for that type of Resource listed in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, unless ERCOT has approved verifiable Resource-specific startup costs for that Resource, under Section 4.4.9.2.4, Verifiable Startup Offer and Minimum-Energy Offer Caps, in which case the Resource's Startup Offer must not be greater than 200% of those approved verifiable Resource-specific Startup Costs.

(5) The Resource's Minimum-Energy Offer must not be greater than 200% of the Resource Category Generic Minimum-Energy Cost for that type of Resource listed in Section 4.4.9.2.3 unless ERCOT has approved verifiable Resource-specific minimum-energy costs for that Resource, under Section 4.4.9.2.4 in which case the Resource's Minimum-Energy Offer must not be greater than 200% of those approved verifiable Resource-specific minimum-energy costs.

(6) Prior to 1000 for the effective DAM, a QSE may submit and update a Three-Part Supply Offer for a Resource for any hours which were Weekly Reliability Unit Commitment (WRUC)-instructed.

4.4.9.2.2 Startup Offer and Minimum-Energy Offer Validation

(1) A valid Startup Offer and Minimum-Energy Offer is an offer that ERCOT has determined meets the criteria listed in Section 4.4.9.2.1, Startup Offer and Minimum-Energy Offer Criteria, and that are part of a Three-Part Supply Offer for which the Energy Offer Curve has also been validated.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any QSE submitting a Startup Offer and Minimum-Energy Offer to view its valid Startup Offers and Minimum-Energy Offers.

(3) ERCOT shall notify the QSE submitting a Startup Offer and Minimum-Energy Offer (which must be part of a Three-Part Supply Offer) if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the offer within the appropriate market timeline.

(4) Where a Split Generation Resource has submitted a Startup Offer and Minimum-Energy Offer, ERCOT shall validate the offers in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, and Distribution Generation Resources, and Distribution Energy Storage Resources.

4.4.9.2.3 Startup Offer and Minimum-Energy Offer Generic Caps

(1) The Resource Category Startup Offer Generic Cap, by applicable Resource category, is determined by the following Operations and Maintenance (O&M) costs by Resource category:

Resource Category	**O&M Costs ($)**
Nuclear, coal, lignite and hydro	7,200
Combined Cycle Generation Resource with a combustion turbine ≥ 90 MW, as determined by the largest combustion turbine in the Combined Cycle Generation Resource and for each combustion turbine in the Combined Cycle Generation Resource	6,810
Combined Cycle Generation Resource with a combustion turbine < 90 MW, as determined by the largest combustion turbine in the Combined Cycle Generation Resource and for each combustion turbine in the Combined Cycle Generation Resource	6,810
Gas steam supercritical boiler	4,800
Gas steam reheat boiler	3,000
Gas steam non-reheat or boiler w/o air-preheater	2,310
Simple cycle greater than 90 MW	5,000
Simple cycle less than or equal to 90 MW	2,300
Reciprocating Engines	$58 /MW * the average of the seasonal net max sustainable ratings
RMR Resource	Not Applicable
Wind generation Resources	0
PhotoVoltaic Generation Resources (PVGRs)	0
Any Resources not defined above	0

(2) The Resource Category Minimum-Energy Generic Cap is the cost per MWh of energy for a Resource to produce energy at the Resource’s LSL and is as follows:

(a) Hydro = $10.00/MWh;

(b) Coal and lignite = $18.00/MWh;

(c) Combined-cycle greater than 90 MW = 8 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(d) Combined-cycle less than or equal to 90 MW = 9 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(e) Gas steam supercritical boiler = 14 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(f) Gas steam reheat boiler = 14.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(g) Gas steam non-reheat or boiler without air-preheater = 16.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(h) Simple-cycle greater than 90 MW = 15.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(i) Simple-cycle less than or equal to 90 MW = 14.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(j) Reciprocating engines = 16.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Minimum-Energy Offer;

(k) RMR Resource = RMR contract estimated fuel cost using its contract I/O curve at its LSL times FIP;

(l) Nuclear = Not Applicable;

(m) Wind generation Resources = $0;

(n) PVGRs = $0; and

(o) Other Resources not defined above = $0.

(3) The FIP and FOP used to calculate the Resource Category Minimum-Energy Generic Cap shall be the FIP or FOP for the Operating Day. In the event the Resource Category Minimum-Energy Generic Cap must be calculated before the FIP or FOP is available for the particular Operating Day, the FIP and FOP for the most recent preceding Operating Day shall be used. Once the FIP and FOP are available for a particular Operating Day, those values shall be used in the calculations. If the percentage fuel mix is not specified for Resource categories having the option to specify the fuel mix, then the minimum of FIP or FOP shall be used.

(4) Items (2)(c) and (2)(d) above are determined by capacity of largest simple-cycle combustion turbine in the train.

4.4.9.2.4 Verifiable Startup Offer and Minimum-Energy Offer Caps

(1) Once verifiable Resource-specific startup costs and minimum-energy costs are established and approved by ERCOT in accordance with Section 5.6.1, Verifiable Costs, then they are used in place of generic costs as described in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps. A QSE may file verifiable unit-specific costs for a Resource at any time, but it is not required to file those costs only because of a DAM commitment. The most recent approved verifiable costs on file must be used going forward.

4.4.9.3 Energy Offer Curve

(1) The Energy Offer Curve represents the QSE's willingness to sell energy at or above a certain price and at a certain quantity in the DAM or its willingness to be dispatched by SCED in Real-Time Operations.

(2) A QSE may submit Resource-specific Energy Offer Curves to ERCOT. Such Energy Offer Curves will be bounded in the DAM for each Operating Hour by the LSL and HSL of the Generation Resource specified in the COP, and bounded in SCED by the LSL and HSL of the Generation Resource as shown by telemetry.

(3) Energy Offer Curves remain active for the offered period until either:

(a) Selected by ERCOT; or

(b) Automatically inactivated by the software at the offer expiration time selected by the QSE.

[NPRR1058: Replace paragraph (3) above with the following upon system implementation:]

(3) Energy Offer Curves remain active for the offered period until automatically inactivated by the software at the offer expiration time selected by the QSE.

(4) For any Operating Hour, the QSE for a Resource may submit or change Energy Offer Curves in the Adjustment Period and a QSE may withdraw an Energy Offer Curve if:

(a) An Output Schedule is submitted for all intervals for which an Energy Offer Curve is withdrawn; or

(b) The Resource is forced Off-Line and notifies ERCOT of the Forced Outage by changing the Resource Status appropriately and updating its COP.

[NPRR1058: Replace paragraph (4) above with the following upon system implementation and renumber accordingly:]

(4) For any Operating Hour, the QSE for a Resource may submit or change Energy Offer Curve information at any time prior to SCED execution, except for the percentage of FIP and percentage of FOP, and SCED will use the latest updated Energy Offer Curve available in the system. The QSE must provide a brief freeform reason at the time of the submission of the Energy Offer Curve if submitted after the end of the Adjustment Period. For the percentage FIP and percentage of FOP within the Energy Offer Curve, submissions and updates must be received by ERCOT's systems in the Adjustment Period. If a new Energy Offer Curve is not deemed to be valid, then the most recent valid Energy Offer Curve available in the system at the time of SCED execution will be used and ERCOT will notify the QSE that the invalid Energy Offer Curve was rejected. Once an Operating Hour ends, an Energy Offer Curve for that hour cannot be submitted, updated, or canceled.

(5) A QSE may withdraw an Energy Offer Curve if:

(a) An Output Schedule is submitted for all intervals for which an Energy Offer Curve is withdrawn; or

(b) The Resource is forced Off-Line and notifies ERCOT of the Forced Outage by changing the Resource Status appropriately and updating its COP.

(5) For any Operating Hour that is a RUC-Committed Interval or a DAM-Committed Interval for a Resource, a QSE for that Resource may not change a Startup Offer or Minimum-Energy Offer.

(6) If a valid Energy Offer Curve or an Output Schedule does not exist for a Resource that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period.

(7) Notwithstanding any other provision in this subsection, a QSE representing an Energy Storage Resource (ESR) may submit or update its Energy Offer Curve for that ESR at any time prior to SCED execution, and SCED will use the latest updated Energy Offer Curve available in the system. If a new Energy Offer Curve is not deemed to be valid, then the most recent valid Energy Offer Curve available in the system at the time of SCED execution will be used and ERCOT will notify the QSE that the invalid Energy Offer Curve was rejected. Once an Operating Hour ends, an Energy Offer Curve for that hour cannot be submitted, updated, or canceled.

[NPRR1014 and NPRR1058: Delete paragraph (7) above upon system implementation.]

4.4.9.3.1 Energy Offer Curve Criteria

(1) Each Energy Offer Curve must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) A monotonically increasing offer curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs;

(d) The first and last hour of the Offer;

(e) The expiration time and date of the offer;

(f) List of Ancillary Service Offers from the same Resource;

(g) Inclusive or exclusive designation relative to other DAM offers; and

(h) Percentage of FIP and percentage of FOP for generation above LSL subject to the sum of the percentages not exceeding 100%.

[NPRR1008 and NPRR1058: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1058:]

(1) Each Energy Offer Curve must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) A monotonically increasing offer curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs;

(d) The first and last hour of the Offer;

(e) The expiration time and date of the offer;

(f) Inclusive or exclusive designation relative to other DAM offers (for Real-Time, Energy Offer Curves are always considered to be inclusive with Ancillary Service Offers);

(g) Percentage of FIP and percentage of FOP for generation above LSL subject to the sum of the percentages not exceeding 100%; and

(h) Reason for update of the offer, if submitting after the end of the Adjustment Period.

(2) An Energy Offer Curve must be within the range of -$250.00 per MWh and the SWCAP in dollars per MWh. The software systems must be able to provide ERCOT with the ability to enter Resource-specific Energy Offer Curve floors and caps.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) An Energy Offer Curve must be within the range of -$250.00 per MWh and either the DASWCAP or RTSWCAP, depending on the timing of the submission, in dollars per MWh.

(3) The minimum amount per Resource for each Energy Offer Curve that may be offered is one MW.

4.4.9.3.2 Energy Offer Curve Validation

(1) A valid Energy Offer Curve is an offer curve that ERCOT has determined meets the criteria listed in Section 4.4.9.3.1, Energy Offer Curve Criteria, and the Energy Offer Curve that is part of a Three-Part Supply Offer for which the Startup Offer and Minimum-Energy Offer has also been validated.

(2) ERCOT shall notify the QSE submitting an Energy Offer Curve by the Messaging System if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the offer within the appropriate market timeline.

(3) ERCOT shall continuously validate Energy Offer Curves and continuously display on the MIS Certified Area information that allows any QSE to view its valid Energy Offer Curves.

4.4.9.3.3 Energy Offer Curve Cost Caps

(1) The following Energy Offer Curve Cost Caps must be used for the purpose of make-whole Settlements, Real-Time High Dispatch Limit Override Energy Payments, and Voltage Support Service Payments:

(a) Nuclear = $15.00/MWh;

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

(c) Combined Cycle greater than 90 MW = 9 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(d) Combined Cycle less than or equal to 90 MW = 10 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(e) Gas - Steam Supercritical Boiler = 10.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(f) Gas Steam Reheat Boiler = 11.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(g) Gas Steam Non-reheat or boiler without air-preheater = 14.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(h) Simple Cycle greater than 90 MW = 14 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(i) Simple Cycle less than or equal to 90 MW = 15 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(j) Reciprocating Engines = 16 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(k) Hydro = $10.00/MWh;

(l) Other = SWCAP;

[NPRR1008: Replace item (l) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(l) Other = DASWCAP or RTSWCAP;

(m) RMR Resource = SWCAP;

[NPRR1008: Replace item (m) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(m) RMR Resource = effective Value of Lost Load (VOLL);

(n) Wind Generation Resources = $0.00/MWh; and

(o) PhotoVoltaic Generation Resource (PVGR) = $0.00/MWh.

(2) ERCOT shall produce an annual report each April that provides the amount of DAM and RUC Make-Whole Payments during the previous calendar year for Resources categorized as Other, per item (1)(l) above, as a percentage of the total amount of DAM and RUC Make-Whole Payments made during the previous calendar year. The report shall be based on final Settlements and include the total number of Resources classified as Other. ERCOT shall present this report annually to the appropriate Technical Advisory Committee (TAC) subcommittee. If there are no Make-Whole Payments for Resources categorized as Other for a given calendar year, then ERCOT will not be required to produce the annual report.

(3) Items in paragraphs (1)(c) and (d) above are determined by capacity of largest simple-cycle combustion turbine in the train selected.

(4) The FIP and FOP used to calculate the Energy Offer Curve Cap for Make-Whole Payment calculation purposes shall be the FIP or FOP for the Operating Day. In the event the Energy Offer Curve Cap for Make-Whole Payment calculation purposes must be calculated before the FIP or FOP is available for the particular Operating Day, the FIP and FOP for the most recent preceding Operating Day shall be used. Once the FIP and FOP are available for a particular Operating Day, those values shall be used in the calculations. If the percentage fuel mix is not specified or if no Energy Offer Curve exists, then the minimum of FIP or FOP shall be used.

4.4.9.4 Mitigated Offer Cap and Mitigated Offer Floor

4.4.9.4.1 Mitigated Offer Cap

(1) Energy Offer Curves may be subject to mitigation in Real-Time operations under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Cap (MOC). ERCOT shall construct an incremental MOC curve in accordance with Section 6.5.7.3 such that each point on the MOC curve is calculated as follows:

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

(1) Energy Offer Curves and Energy Bid/Offer Curves may be subject to mitigation in Real-Time operations under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Cap (MOC). For Generation Resources, ERCOT shall construct an incremental MOC curve in accordance with Section 6.5.7.3 such that each point on the MOC curve is calculated as follows:

$$\text{MOC}_{q,\, r,\, h} = \text{Max}\ [\text{GIHR}_{q,\, r} * \text{Max}(\text{FIP},\ \text{WAFP}_{q,\, r,\, h}),\ (\text{IHR}_{q,\, r} * \text{FPRC}_{q,\, r} + \text{OM}_{q,\, r}) * \text{CFMLT}_{q,\, r}]$$

[NPRR1058: Replace the formula "$MOC_{q, r, h}$" above with the following upon system implementation:]

$$MOC_{q, r, h} = \text{Max}\ [GIHR_{q, r} * \text{Max}(FIP, WAFP_{q, r, h}), (IHR_{q, r} * FPRC_{q, r} + OM_{q, r})]$$

Where,

If a QSE has submitted an Energy Offer Curve on behalf of a Generation Resource and the Generation Resource has approved verifiable costs, then

$$FPRC_{q, r} = \text{Max}(WAFP_{q, r, h}, FIP + FA_{q, r}) * RTPERFIP_{q, r} / 100 + FOP * RTPERFOP_{q, r} / 100$$

If a QSE has not submitted an Energy Offer Curve on behalf of a Generation Resource and the Generation Resource has approved verifiable costs, then

$$FPRC_{q, r} = \text{Max}(WAFP_{q, r, h}, FIP + FA_{q, r}) * GASPEROL_{q, r} / 100 + FOP * OILPEROL_{q, r} / 100 + (SFP + FA_{q, r}) * SFPEROL_{q, r} / 100$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$MOC_{q, r, h}$	\$/MWh	*Mitigated Offer Cap per Resource*—The MOC for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$GIHR_{q, r}$	MMBtu/MWh	*Generic Incremental Heat Rate*—The generic, single-value, incremental heat rate. For Generation Resources with a Commercial Operations Date on or before January 1, 2004, the generic incremental heat rate shall be set to 10.5. For Generation Resources that have a Commercial Operations Date after January 1, 2004, this value shall be set to 14.5. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$IHR_{q, r}$	MMBtu/MWh	*Verifiable Incremental Heat Rate per Resource*—The verifiable incremental heat rate curve for Resource *r,* as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
FIP	\$/MMBtu	*Fuel Index Price*—The natural gas index price as defined in Section 2.1, Definitions.
$RTPERFIP_{q, r}$	none	*Fuel Index Price Percentage*—The percentage of natural gas used by Resource *r* to operate above LSL, as submitted with the energy offer curve.
FOP	\$/MMBtu	*Fuel Oil Price*—The fuel oil index price as defined in Section 2.1.
$RTPERFOP_{q, r}$	none	*Fuel Oil Price Percentage*—The percentage of fuel oil used by Resource *r* to operate above LSL, as submitted with the energy offer curve.
SFP	\$/MMBtu	*Solid Fuel Price*—The solid fuel index price is \$1.50.
$FPRC_{q, r}$	\$/MMBtu	*Fuel Price Calculated per Resource*—The calculated index price for fuel for the Resource based on the Resources fuel mix. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	Unit	Definition
GASPEROL $_{q, r}$	none	*Percent of Natural Gas to Operate Above LSL*—The percentage of natural gas used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.
OILPEROL $_{q, r}$	none	*Percent of Oil to Operate Above LSL*—The percentage of fuel oil used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.
SFPEROL $_{q, r}$	none	*Percent of Solid Fuel to Operate Above LSL*—The percentage of solid fuel used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.
FA $_{q, r}$	$/MMBtu	*Fuel Adder*—The fuel adder is the average cost above the index price Resource *r* has paid to obtain fuel. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
OM $_{q, r}$	$/MWh	*Variable Operations and Maintenance Cost above LSL*—The O&M cost for Resource *r* to operate above LSL, including an adjustment for emissions costs, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
CFMLT $_{q, r}$	none	*Capacity Factor Multiplier*—A multiplier based on the corresponding monthly capacity factor as described in paragraph (1)(d) below.
[NPRR1058: Delete the variable "CFMLT $_{q, r}$" above upon system implementation.]		
WAFP $_{q, r, h}$	$/MMBtu	*Weighted Average Fuel Price*—The volume-weighted average intraday, same-day and spot price of fuel submitted to ERCOT during the Adjustment Period for a specific Resource and specific hour within the Operating Day, as described in paragraph (1)(f) below.
q	none	A QSE.
r	none	A Generation Resource.
h	none	The Operating Hour.

(a) For a Resource contracted by ERCOT under paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority, ERCOT shall increase the O&M cost such that every point on the MOC curve is greater than the SWCAP in $/MWh.

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

(a) For a Resource contracted by ERCOT under paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority, ERCOT shall increase the O&M cost such that every point on the MOC curve is greater than the effective Value of Lost Load (VOLL) in $/MWh.

(b) Notwithstanding the MOC calculation described in paragraph (1) above, the MOC for ESRs shall be set at the SWCAP. No later than December 31, 2023, ERCOT and stakeholders shall submit a report to TAC that includes a recommendation to continue the existing approach or a proposal to implement an alternative approach to determine the MOC for ESRs.

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

(b) Notwithstanding the MOC calculation described in paragraph (1) above, the MOC for ESRs shall be set at the RTSWCAP. No later than December 31, 2023, ERCOT and stakeholders shall submit a report to TAC that includes a recommendation to continue the existing approach or a proposal to implement an alternative approach to determine the MOC for ESRs.

(c) For Quick Start Generation Resources (QSGRs) the MOC shall be adjusted in accordance with Verifiable Cost Manual Appendix 7, Calculation of the Variable O&M Value and Incremental Heat Rate used in Real Time Mitigation for Quick Start Generation Resources (QSGRs).

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

(d) For On-line hydro Generation Resources not operating in Synchronous Condenser Fast-Response mode, the MOC shall be adjusted in accordance with Verifiable Cost Manual, Appendix 12, Calculation of the Variable O&M Value and Incremental Heat Rate used in Real Time Mitigation for On-Line Hydro Generation Resources not operating in Synchronous Condenser Fast-Response mode.

(d) The multipliers for the MOC calculation above are as follows:

(i) 1.10 for Resources running at a ≥ 50% capacity factor for the previous 12 months;

(ii) 1.15 for Resources running at a ≥ 30 and < 50% capacity factor for the previous 12 months;

(iii) 1.20 for Resources running at a ≥ 20 and < 30% capacity factor for the previous 12 months;

(iv) 1.25 for Resources running at a ≥ 10 and < 20% capacity factor for the previous 12 months;

(v) 1.30 for Resources running at a ≥ 5 and < 10% capacity factor for the previous 12 months;

(vi) 1.40 for Resources running at a ≥ 1 and < 5% capacity factor for the previous 12 months; and

(vii) 1.50 for Resources running at a less than 1% capacity factor for the previous 12 months.

[NPRR1058: Delete paragraph (d) above upon system implementation and renumber accordingly.]

(e) The previous 12 months' capacity factor must be updated by ERCOT by the 20th day of each month using the most recent data for use in the next month. ERCOT shall post to the MIS Secure Area the capacity factor for each Resource before the start of the effective month.

[NPRR1058: Delete paragraph (e) above upon system implementation and renumber accordingly.]

(f) During the Adjustment Period, a QSE representing a Resource may submit Exceptional Fuel Cost as a volume-weighted average fuel price for use in the MOC calculation for that Resource. To qualify as Exceptional Fuel Cost, the submission must meet the following conditions:

(i) For all Resources, the weighted average fuel price must exceed FIP for the applicable Operating Day, plus a threshold parameter value of $1/MMBtu, plus the applicable fuel adder. For Resources without approved verifiable costs, the fuel adder will be set to the default value assigned to Resources with approved verifiable costs, as defined in the Verifiable Cost Manual. The threshold parameter value in this paragraph shall be recommended by the Wholesale Market Subcommittee (WMS) and approved by the Technical Advisory Committee (TAC). ERCOT shall update the threshold value on the first day of the month following TAC approval unless otherwise directed by the TAC. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.

(ii) Fixed cost (fees, penalties and similar non-gas costs) may not be included in the calculation of the weighted average fuel price.

(iii) All intra-day, same day, and spot fuel purchases must be included in the calculation of the weighted average fuel price in paragraph (1) above. These must account for at least 10% of the total fuel volume burned by the applicable Resource for the hour for which the weighted average fuel price is computed. As noted in paragraph (l) below, the methodology used in the allocation of the cost and volume of purchased fuel to the Resource for the hour is subject to validation by ERCOT.

(iv) Weighted average fuel prices must be submitted individually for each Operating Hour for which they are applicable. Values submitted outside of the Adjustment Period will be rejected and not used in the calculation of the MOC for the designated Operating Hour.

(g) ERCOT may notify the Independent Market Monitor (IMM) if a QSE submits an Exceptional Fuel Cost.

(h) No later than five Business Days after an Operating Day for which an Exceptional Fuel Cost is submitted, ERCOT shall issue a Market Notice indicating the affected Operating Hours and the number of Resources for which a QSE submitted Exceptional Fuel Cost for a particular Operating Day.

[NPRR1121: Replace paragraph (h) above with the following upon system implementation:]

(h) The day following an Operating Day for which an Exceptional Fuel Cost is submitted, ERCOT shall post a report on the ERCOT website indicating the affected Operating Hours and the number of Resources for which a QSE submitted Exceptional Fuel Cost for a particular Operating Day.

(i) No later than 1700 Central Prevailing Time (CPT) on the 15th day following an Exceptional Fuel Cost submission, the submitting QSE shall provide ERCOT with the calculation of the weighted average fuel price, intraday or same-day fuel purchases, and any available supporting documentation. Such information may include, but is not limited to, documents of the following nature: relevant contracts between the QSE or Resource Entity and fuel supplier, trade logs, transportation, storage, balancing and distribution agreements, calculation of the weighted average fuel price, or any other documentation necessary to support the Exceptional Fuel Cost price and volume for the applicable period(s).

(j) No later than 1700 Central Prevailing Time (CPT) on the 60th day following an Exceptional Fuel Cost submission, the submitting QSE shall provide ERCOT with all supporting documentation not previously provided to ERCOT. No supporting documentation will be accepted after the 60th day.

(k) The accuracy of submitted Exceptional Fuel Cost and the need for purchasing intraday or same-day gas must be attested to by a duly authorized officer or agent of the QSE representing the Resource. The attestation must be provided in a standardized format acceptable to ERCOT and submitted with the other documentation described in paragraph (i) above.

(l) ERCOT will use the supporting documentation to validate the Exceptional Fuel Cost for the applicable period. Validation will include, but not be limited to, the cost and the quantity of purchased fuel, Resource-specific heat rates, and the methodology used in the allocation of the cost and volume of purchased fuel to the Resource for the applicable hour used in the weighted average fuel price calculation. In connection with the validation process ERCOT may request additional documentation or clarification of previously submitted documentation. Such requests must be honored within ten Business Days.

(m) At ERCOT's sole discretion, submission and follow-up information deadlines may be extended on a case-by-case basis.

4.4.9.4.2 Mitigated Offer Floor

(1) Energy Offer Curves may be subject to mitigation in the Real-Time Market (RTM) under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Floor. The Mitigated Offer Floor is:

Resource Category	Mitigated Offer Floor
Nuclear and Hydro	-$250/MWh
Coal and Lignite	-$20/MWh
Combined Cycle	-$20/MWh
Gas/Oil Steam and Combustion Turbine	-$20/MWh
Qualifying Facility (QF)	-$50/MWh
Wind	-$100/MWh
PhotoVoltaic (PV)	-$50/MWh
Other	-$50/MWh

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

(1) Energy Offer Curves and Energy Bid/Offer Curves may be subject to mitigation in the RTM under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Floor. The Mitigated Offer Floor is:

Resource Category	Mitigated Offer Floor
Nuclear and Hydro	-$250/MWh
Coal and Lignite	-$20/MWh
Combined Cycle	-$20/MWh
Gas/Oil Steam and Combustion Turbine	-$20/MWh
Qualifying Facility (QF)	-$50/MWh
Wind	-$100/MWh
PhotoVoltaic (PV)	-$50/MWh
Energy Storage Resource (ESR)	-$250/MWh
Other	-$50/MWh

[NPRR826: Insert Section 4.4.9.4.3 below upon system implementation:]

4.4.9.4.3 Mitigated Offer Cap for RMR Resources

(1) For each Resource contracted by ERCOT under Section 3.14.1, Reliability Must Run, the Resource's MOC curve for use in the SCED process is determined using the steps below when the Resource's offer is subject to mitigation in accordance with Section 3.19, Constraint Competitiveness Tests. The single price ($/MWh) value determined below will be used as the MOC curve for the full operating range of the Resource. The calculations will occur between the first and second step within the SCED process as well as during the process for determining Real-Time On-Line Reliability Deployment Price Adder. This analysis will only be applied to active constraints for which the contracted Resource has a more than 2% unloading Shift Factor on the Transmission Facility(s), more than 5% unloading impact on the Transmission Facility(s) based on telemetered HSL, and if at least one other Resource not contracted by ERCOT under Section 3.14.1 has an unloading Shift Factor of 5% or more relative to the constraint(s). If this criteria is not met, the MOC curve for the Resource shall be calculated in accordance with Section 4.4.9.4.1, Mitigated Offer Cap, and Section 5.6.1, Verifiable Costs.

(a) For each Resource that is not a Resource contracted by ERCOT under Section 3.14.1 or paragraph (4) of Section 6.5.1.1 and that has an unloading Shift Factor of at least RMRSF percent relative to the constraint(s), determine the higher of zero or the difference between the price ($/MWh) at HSL from the Energy Offer Curves determined for use in SCED Step 2, which may or may not be mitigated, and system lambda from SCED Step 1 and divide that difference by the absolute value of that Resource's Shift Factor for the corresponding constraint. The value of RMRSF will default to 5% until a different value is approved by TAC considering the analysis and data used by ERCOT to determine the need for the contracted Resource under Section 3.14.1. ERCOT shall post the current TAC-approved value(s) of RMRSF on the ERCOT website.

(b) For each constraint, identify the largest value that is less than maximum Shadow Price for the specific constraint.

(c) For each SCED interval for each constraint, determine a value equal to the minimum of:

(i) The value determined in paragraph (b) above plus $0.01/MWh; and

(ii) The maximum Shadow Price for the constraint minus $1/MWh.

(d) For each SCED interval for each constraint, multiply the resulting value from paragraph (c) above by the absolute value of the Shift Factor of the Resource contracted by ERCOT to the corresponding constraint. For SCED intervals in which there are multiple constraints which are being analyzed, the lowest value is used for the SCED interval.

(e) If the value from paragraph (b) above for any constraint analyzed is zero, the MOC curve for the RMR Resource shall be calculated in accordance with Section 4.4.9.4.1 and Section 5.6.1. If the value from paragraph (b) above for every constraint analyzed is greater than zero, the RMR Resource's MOC curve for use in Step 2 of the SCED process is the sum of system lambda from Step 1 of SCED in the interval and the value from (d) above.

4.4.9.5 DAM Energy-Only Offer Curves

(1) A QSE must submit any DAM Energy-Only Offer Curves by 1000 for the effective DAM.

(2) The DAM Energy-Only Offer Curve represents the QSE's willingness to sell energy at or above a certain price and at a certain quantity at a specific Settlement Point in the DAM. A DAM Energy-Only Offer Curve may be offered only in the DAM.

(3) DAM Energy-Only Offer Curves are not Resource-specific.

4.4.9.5.1 DAM Energy-Only Offer Curve Criteria

(1) Each DAM Energy-Only Offer Curve must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Settlement Point;

(c) The fixed quantity block, variable quantity block, or curve indicator for the offer;

   (i) If a fixed quantity block, the single price (in \$/MWh) and single quantity (in MW) for all hours offered in that block , which may clear at a Settlement Point Price less than the offer price for that block;

   (ii) If a variable quantity block, the single price (in \$/MWh) and single "up to" quantity (in MW) contingent on the purchase of all hours offered in that block; and

   (iii) If a curve, a monotonically increasing energy offer curve for both price (in \$/MWh) and quantity (in MW) with no more than ten price/quantity pairs;

(d) The first and last hour of the offer; and

(e) The expiration time and date of the offer.

(2) A DAM Energy-Only Offer Curve must be within the range of -\$250.00 per MWh and the SWCAP in dollars per MWh.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) A DAM Energy-Only Offer Curve must be within the range of -\$250.00 per MWh and the DASWCAP in dollars per MWh.

(3) The minimum amount for each DAM Energy-Only Offer Curve that may be offered is one MW.

(4) DAM Energy-Only Offers, DAM Energy Bids, and/or PTP Obligation bids shall not be submitted in combination to create the net effect of a single PTP Obligation containing a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points for the QSE or for any combination of QSEs within the same Counter-Party.

4.4.9.5.2 DAM Energy-Only Offer Validation

(1) A valid DAM Energy-Only Offer Curve is an offer that ERCOT has determined meets the criteria listed in Section 4.4.9.5.1, DAM Energy-Only Offer Curve Criteria.

(2) ERCOT shall notify the QSE submitting a DAM Energy-Only Offer Curve by the Messaging System if the offer was rejected or was considered invalid for any reason, with the exception of paragraph (4) of Section 4.4.9.5.1. The QSE may then resubmit the offer within the appropriate market timeline.

(3) ERCOT shall continuously validate DAM Energy-Only Offers and continuously display on the MIS Certified Area information that allows any QSE to view its valid DAM Energy-Only Offers.

4.4.9.6 DAM Energy Bids

(1) A QSE must submit any DAM Energy Bids by 1000 for the effective DAM.

(2) A DAM Energy Bid represents the QSE's willingness to buy energy at or below a certain price and at a certain quantity at a specific Settlement Point in the DAM. A DAM Energy Bid may be made only in the DAM.

4.4.9.6.1 DAM Energy Bid Criteria

(1) Each DAM Energy Bid must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The Settlement Point;

(c) Fixed quantity block, variable quantity block, or curve indicator for the bid;

(i) If a fixed quantity block, the single price (in \$/MWh) and single quantity (in MW) for all hours bid in that block, which may clear at a Settlement Point Price greater than the bid price for that block;

(ii) If a variable quantity block, the single price (in \$/MWh) and single "up to" quantity (in MW) contingent on the purchase of all hours bid in that block; and

(iii) If a curve, a monotonically decreasing energy bid curve for price (in \$/MWh) and monotonically increasing for quantity (in MW) with no more than 10 price/quantity pairs.

(d) The first and last hour of the bid; and

(e) The expiration time and date of the bid.

(2) The minimum amount for each DAM Energy Bid that may be bid is one MW.

(3) DAM Energy-Only Offers, DAM Energy Bids, and/or PTP Obligation bids shall not be submitted in combination to create the net effect of a single PTP Obligation containing a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points for the QSE or for any combination of QSEs within the same Counter-Party.

4.4.9.6.2 DAM Energy Bid Validation

(1) A valid DAM Energy Bid is a bid that ERCOT has determined meets the criteria listed in Section 4.4.9.6.1, DAM Energy Bid Criteria.

(2) ERCOT shall notify the QSE submitting a DAM Energy Bid by the Messaging System if the bid was rejected or was considered invalid for any reason, with the exception of paragraph (3) of Section 4.4.9.6.1. The QSE may then resubmit the bid within the appropriate market timeline.

(3) ERCOT shall continuously validate DAM Energy Bids and continuously display on the MIS Certified Area information that allows any QSE to view its valid DAM Energy Bids.

[NPRR1014: Insert Section 4.4.9.7 below upon system implementation:]

4.4.9.7 Energy Bid/Offer Curve

(1) The Energy Bid/Offer Curve represents the willingness of a QSE representing an ESR to buy energy at or below a certain price and sell energy at or above a certain price and at a certain quantity in the DAM or its willingness to be dispatched by SCED in Real-Time Operations. ERCOT must validate each Energy Bid/Offer Curve in accordance with Section 4.4.9.7.2, Energy Bid/Offer Curve Validation, before it can be used in any ERCOT process.

(2) A QSE may submit Resource-Specific Energy Bid/Offer Curves to ERCOT. Such Energy Bid/Offer Curves will be bounded in the DAM for each Operating Hour by the LSL and HSL of the ESR specified in the COP, and bounded in SCED by the LSL and HSL of the ESR as shown by telemetry.

(3) In the DAM, ERCOT will not consider COP Resource Status when evaluating Energy Bid/Offer Curves. In the Real-Time Market (RTM), SCED will consider an ESR unavailable for SCED Dispatch when the ESR's Resource Status is OUT.

(4) Energy Bid/Offer Curves remain active for the offered period until either:

(a) Selected by ERCOT; or

(b) Automatically inactivated by the software at the offer expiration time selected by the QSE.

(5) In the RTM, a QSE may submit or change an Energy Bid/Offer Curve at any time prior to SCED execution, and SCED will use the latest updated Energy Bid/Offer Curve available in the system. If a new Energy Bid/Offer Curve is not deemed to be valid, then the most recent valid Energy Bid/Offer Curve available in the system at the time of SCED execution will be used and ERCOT will notify the QSE that the invalid

Energy Bid/Offer Curve was rejected. Once an Operating Hour ends, an Energy Bid/Offer Curve for that hour cannot be submitted, updated, or canceled.

(6) A QSE may withdraw an Energy Bid/Offer Curve if:

(a) An Output Schedule is submitted for all intervals for which an Energy Bid/Offer Curve is withdrawn; or

(b) The ESR is forced Off-Line and notifies ERCOT of the Forced Outage by changing the Resource Status appropriately and updating its COP.

(7) At the time of SCED execution, if a valid Energy Bid/Offer Curve or Output Schedule does not exist for an ESR that has a status of On-Line, then ERCOT shall notify the QSE and create a proxy Energy Bid/Offer Curve priced at -$250/MWh for the portion of the curve less than zero MW, and priced at the RTSWCAP for the portion of the curve greater than zero MW.

[NPRR1014: Insert Section 4.4.9.7.1 below upon system implementation:]

4.4.9.7.1 Energy Bid/Offer Curve Criteria

(1) Each Energy Bid/Offer Curve must be reported by a QSE representing an ESR and must include the following information:

(a) The selling QSE;

(b) The ESR represented by the QSE from which the bid and offer would be provided;

(c) A monotonically non-decreasing curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs. Negative MW values cover the charging MW range, and the positive MW values cover the discharging MW range. The price points corresponding to the charging MW range represent the not-to-exceed bid prices to consume energy, and the price points corresponding to the discharging MW range represent the offer prices to sell energy;

(d) The first and last hour of the offer;

(e) The expiration time and date of the offer;

(2) An Energy Bid/Offer Curve shall be bounded by -$250.00 per MWh and either the DASWCAP or RTSWCAP depending on the timing of the submission in dollars per MWh. The ERCOT systems must allow ERCOT to enter ESR-specific Energy Bid/Offer Curve floors and caps.

(3) In Day-Ahead Market (DAM) and Real-Time Market (RTM), an Energy Bid/Offer Curve shall be considered to be inclusive of Ancillary Service Offers.

[NPRR1014: Insert Section 4.4.9.7.2 below upon system implementation:]

4.4.9.7.2 Energy Bid/Offer Curve Validation

(1) A valid Energy Bid/Offer Curve is a curve that ERCOT has determined meets the criteria listed in Section 4.4.9.7.1, Energy Bid/Offer Curve Criteria.

(2) ERCOT shall notify the QSE submitting an Energy Bid/Offer Curve by the Messaging System if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the Energy Bid/Offer Curve within the appropriate market timeline.

(3) ERCOT shall continuously validate Energy Bid/Offer Curves and continuously display on the MIS Certified Area information that allows any QSE to view its valid Energy Bid/Offer Curves.

4.4.10 Credit Requirement for DAM Bids and Offers

(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:

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

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

(2) ERCOT may adjust *e1* by changing the quantity of bids or offers to the values reported by the Counter-Party in paragraph (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:

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

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

(2) ERCOT may adjust *e1* by changing the quantity of bids or offers to the values reported by the Counter-Party in paragraph (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:

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

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

(b) 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 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 hourly difference of Real-Time Settlement Point Price and DASPP 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 hourly difference of Real-Time Settlement Point Price and DASPP 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 hourly difference of Real-Time Settlement Point Price and DASPP 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 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 = (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

Parameter	**Unit**	**Current Value***
b	percentile	45
dp	percentile	90
ep2	percentile	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:

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

Parameter	**Unit**	**Current Value**
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.		

4.4.11 System-Wide Offer Caps

(1) The SWCAP shall be determined in accordance with the Public Utility Commission of Texas (PUCT) Substantive Rules. The methodology for determining the SWCAP is as follows:

(a) The Low System-Wide Offer Cap (LCAP) is set at $2,000 per MWh for energy and $2,000 per MW per hour for Ancillary Services.

(b) At the beginning of each year, the SWCAP shall be set equal to the High System-Wide Offer Cap (HCAP) and maintained at this level as long as the Peaker Net Margin (PNM) during a year is less than or equal to the PNM threshold per MW-year. If the PNM exceeds the PNM threshold per MW-year during a year, on the next Operating Day, the SWCAP shall be reset to the LCAP for the remainder of that year.

(c) ERCOT shall set the PNM threshold at three times the cost of new entry of new generation plants.

The above parameters are defined as follows.

Parameter	**Unit**	**Current Value***
HCAP	$/MWh	5,000
PNM threshold	$/MW-year	315,000
* 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.		

(2) Any offers that exceed the current SWCAP shall be rejected by ERCOT.

[NPRR1008: Replace Section 4.4.11 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.4.11 Day-Ahead and Real-Time System-Wide Offer Caps

(1) The DASWCAP and RTSWCAP shall be determined in accordance with the Public Utility Commission of Texas (PUCT) Substantive Rules. The methodology for determining the DASWCAP and RTSWCAP is as follows:

(a) The Low System-Wide Offer Cap (LCAP) is set at $2,000 per MWh for energy and $2,000 per MW per hour for Ancillary Services.

(b) At the beginning of each year, the DASWCAP and RTSWCAP shall be set equal to the respective High System-Wide Offer Cap (HCAP) and maintained at this level as long as the Peaker Net Margin (PNM) during a year is less than or equal to the PNM threshold per MW-year. Additionally, the Value of Lost Load (VOLL) used to determine the ASDCs for DAM and RTM shall be set to the HCAP for DAM. If the PNM exceeds the PNM threshold per MW-year the DASWCAP and the VOLL used to determine the ASDCs for DAM and RTM shall be reset per the schedule in Section 4.4.11.1, Scarcity Pricing Mechanism.

(c) ERCOT shall set the PNM threshold at three times the cost of new entry of new generation plants.

The above parameters are defined as follows:

Parameter	**Unit**	**Current Value***
HCAP – DAM (DASWCAP)	$/MWh	5,000
HCAP – RTM (RTSWCAP)	$/MWh	2,000
PNM threshold	$/MW-year	315,000
* 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.		

(2) Any offers that exceed the current respective SWCAP shall be rejected by ERCOT.

4.4.11.1 Scarcity Pricing Mechanism

(1) ERCOT shall operate the scarcity pricing mechanism in accordance with the PUCT Substantive Rules. The methodology for determining the scarcity pricing mechanism is as follows:

(a) The scarcity pricing mechanism operates on a calendar year basis.

(b) For each day of the year, the Peaking Operating Cost (POC) shall be ten times the effective daily FIP. The POC is calculated in dollars per MWh.

(c) For the purpose of this Section, the Real-Time Energy Price (RTEP) shall be measured as the ERCOT Hub Average 345 kV Hub price.

(d) For the current year, the PNM shall be calculated in dollars per MW on a cumulative basis for all past intervals in the year as follows:

∑((RTEP – POC) * (0.25)) for each Settlement Interval where (RTEP – POC) > 0

(2) By the end of the next Business Day following the applicable Operating Day, ERCOT shall post the updated value of the PNM and the current SWCAP on the ERCOT website.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) By the end of the next Business Day following the applicable Operating Day, ERCOT shall post the updated value of the PNM and the current DASWCAP on the ERCOT website.

(3) When the calculated PNM exceeds PNM threshold per MW-year, the SWCAP shall be changed to the LCAP in the following manner:

(a) On the Operating Day that the PNM exceeds PNM threshold the HCAP will remain in effect for the balance of the day (Day 1).

(b) During the next Operating Day (Day 2), ERCOT shall send a Market Notice that the LCAP is going into effect for the following Operating Day (Day 3). At the end of Day 2 and following the last SCED interval at approximately 2355, the System Operator will approve the switchover from the HCAP to the LCAP.

(c) All SCED intervals for Day 3 and through the end of the calendar year will use the LCAP.

(d) On December 31 following the last SCED interval at approximately 2355, the System Operator will approve the switchover from the LCAP up to the HCAP for the next year.

[NPRR1008: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) When the calculated PNM exceeds PNM threshold per MW-year, the DASWCAP and the VOLL used to determine the ASDCs for DAM and RTM shall both be changed to the LCAP for the remainder of the calendar year, in the following manner:

(a) On the Operating Day that the PNM exceeds the PNM threshold, the HCAP will remain in effect for the balance of the day and for the Operating Day thereafter (Days 1 and 2).

(b) On the Operating Day after the PNM exceeds the PNM threshold (Day 2) prior to the execution of DAM, ERCOT shall send a Market Notice that the DASWCAP and the VOLL used to determine the ASDCs for DAM and RTM will both be changed to LCAP, effective for the following Operating Day (Day 3).

(c) For the Operating Day two days after the PNM threshold is exceeded (Day 3) and through the end of the calendar year, DAM and RTM will use the LCAP and ASDCs reflecting the updated VOLL.

(d) On December 31, for Operating Day January 1, DASWCAP and the VOLL used to determine the ASDCs for the DAM and RTM will be reset to the HCAP for DAM for the new Resource adequacy cycle.

[NPRR1008: Insert Section 4.4.12 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.4.12 Determination of Ancillary Service Demand Curves for the Day-Ahead Market and Real-Time Market

(1) This Section describes the process for determining ASDCs for Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) for the Day-Ahead Market (DAM) and Real-Time Market (RTM). This section does not apply to ASDCs used in the Reliability Unit Commitment (RUC) process.

(2) The DAM shall use the same ASDCs as the RTM, as an initial condition. Specific to the DAM, the ASDCs will be adjusted, as needed, to account for negative Self-Arranged Ancillary Service Quantities.

(3) For Reg-Down, the ASDC shall be a constant value equal to VOLL for the full range of the Ancillary Service Plan for Reg-Down.

(4) To determine the individual ASDCs for Reg-Up, RRS, ECRS, and Non-Spin, an Aggregate ORDC (AORDC) will be created and then disaggregated into individual curves for the different Ancillary Services.

(5) ERCOT shall develop the AORDC from historical data from the period of June 1, 2014 through December 31, 2023 as follows:

(a) For all SCED intervals where the sum of RTOLCAP and RTOFFCAP is less than 10,000 MW, use the RTOLCAP and RTOFFCAP values to calculate the AORDC as follows:

$$\boldsymbol{AORDC = \Big(0.5 * \big(1 - pnorm(RTOLCAP - 2000,\ 0.5 * \mu,\ 0.707 * \sigma)\big) + 0.5 * \big(1 - pnorm(RTOLCAP + RTOFFCAP - 2000,\ \mu,\ \sigma)\big)\Big) * \big(VOLL - min(System\ Lambda, 250)\big)}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTOLCAP	MWh	*Real-Time On-Line Reserve Capacity* – The Real-Time reserve capacity of On-Line Resources available for the SCED intervals beginning June 1, 2014 through December 31, 2023
RTOFFCAP	MWh	*Real-Time Off-Line Reserve Capacity* – The Real-Time reserve capacity of Off-Line Resources available for the SCED intervals beginning June 1, 2014 through December 31, 2023.
μ	None	The mean value of the shifted LOLP distribution as published for Fall 2024
σ	None	The standard deviation of the shifted LOLP distribution as published for Fall 2024

(b) Using the results of step (a) above, use regression methods to fit a curve to the average reserve pricing outcomes for the various MW reserve levels.

(c) Calculate points on the regression curve in 1 MW increments for any observed reserve level >= 2,000 MW and price >$0.01/MWh. These points form the AORDC.

(6) ERCOT shall disaggregate the AORDC developed pursuant to paragraph (5) above into individual ASDCs for each Ancillary Service product as follows:

(a) The ASDC for all Reg-Up in the Ancillary Service Plan shall use the highest price portion of the AORDC;

(b) The ASDC for all RRS in the Ancillary Service Plan shall use the highest price portion of the remaining AORDC after removing the portion of the AORDC that was used for the Reg-Up ASDC;

(c) The ASDC for all ECRS in the Ancillary Service Plan shall use the highest price portion of the remaining AORDC after removing the portions of the AORDC that were used for the Reg-Up and RRS ASDCs;

(d) The ASDC for Non-Spin shall use the remaining portion of the remaining AORDC after removing the portions of the AORDC that were used for the Reg-Up, RRS, and ECRS ASDCs.

(7) Each ASDC will be represented by a 100-point linear approximation to the corresponding part of the AORDC. Fewer points may be used for cases where it would not result in decreased accuracy in representing the corresponding part of the AORDC.

(8) Should the PNM exceed the PNM threshold per MW-year, as described in Protocol Section 4.4.11.1, Scarcity Pricing Mechanism, the AORDC used in determining the individual ASDCs will be adjusted to reflect the updated value of VOLL for the remainder of the annual Resource adequacy cycle. The AORDC will be reset to use the HCAP for DAM at the start of the next calendar year.

4.5 DAM Execution and Results

4.5.1 DAM Clearing Process

(1) At 1000 in the Day-Ahead, ERCOT shall start the Day-Ahead Market (DAM) clearing process. If the processing of DAM bids and offers after 0900 is significantly delayed or impacted by a failure of ERCOT software or systems that directly impacts the DAM, ERCOT shall post a Notice as soon as practicable on the ERCOT website, in accordance with paragraph (1) of Section 4.1.2, Day-Ahead Process and Timing Deviations, extending the start time of the execution of the DAM clearing process by an amount of time at least as long as the duration of the processing delay plus ten minutes. In no event shall the extension exceed more than one hour from when the processing delay is resolved.

(2) ERCOT shall complete a Day-Ahead Simultaneous Feasibility Test (SFT). This test uses the Day-Ahead Updated Network Model topology and evaluates all Congestion Revenue Rights (CRRs) for feasibility to determine hourly oversold quantities.

(3) The purpose of the DAM is to economically and simultaneously clear offers and bids described in Section 4.4, Inputs into DAM and Other Trades.

(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to security and other constraints, and ERCOT Ancillary Service procurement requirements.

(a) The bid-based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation bids.

(b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers and Ancillary Service Offers.

(c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following:

(i) Transmission constraints – transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies. These constraints may represent:

(A) Thermal constraints – protect Transmission Facilities against thermal overload.

(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.

(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained.

(ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers:

(A) Resource output constraints – the Low Sustained Limit (LSL) and High Sustained Limit (HSL) of each Resource; and

(B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.

(iii) Other constraints –

(A) Linked offers – the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour, provided that linked Energy and Off-Line Non-Spinning Reserve (Non-Spin) Ancillary Service Offers are not awarded in the same Operating Hour.

(B) The sum of the awarded Ancillary Service capacities for each Resource must be within the Resource limits specified in the Current Operating Plan (COP) and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource Parameters as described in Section 3.7, Resource Parameters.

(C) Block Ancillary Service Offers for a Load Resource – blocks will not be cleared unless the entire quantity block can be awarded. Because block Ancillary Service Offers cannot set the Market Clearing Price for Capacity (MCPC), a block Ancillary Service Offer may clear below the Ancillary Service Offer price for that block.

(D) Block DAM Energy Bids, DAM Energy-Only Offers, and PTP Obligation bids – blocks will not be cleared unless the entire time and/or quantity block can be awarded. Because quantity block bids and offers cannot set the Settlement Point Price, a quantity block bid or offer may clear in a manner inconsistent with the bid or offer price for that block.

(E) Combined Cycle Generation Resources – The DAM may commit a Combined Cycle Generation Resource in a time period that includes the last hour of the Operating Day only if that Combined Cycle Generation Resource can transition to a shutdown condition in the DAM Operating Day.

(d) Ancillary Service needs for each Ancillary Service include the needs specified in the Ancillary Service Plan that are not part of the Self-Arranged Ancillary Service Quantity and that must be met from available DAM Ancillary Service Offers while co-optimizing with DAM Energy Offers. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service. See Section 4.5.2, Ancillary Service Insufficiency, for what happens if insufficient Ancillary Service Offers are received in the DAM.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues, including revenues based on Ancillary Service Demand Curves (ASDCs), minus the offer-based costs over the Operating Day, subject to security and other constraints.

(a) The bid-based revenues include revenues from ASDCs, DAM Energy Bids, bid portions of Energy Bid/Offer Curves, and Point-to-Point (PTP) Obligation bids.

(b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers, offer portions of Energy Bid/Offer Curves, Ancillary Service Only Offers, and Ancillary Service Offers.

(c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following:

(i) Transmission constraints – transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies. These constraints may represent:

(A) Thermal constraints – protect Transmission Facilities against thermal overload.

(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.

(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained.

(ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers or Energy Bid/Offer Curves:

(A) Resource output constraints – the Low Sustained Limit (LSL) and High Sustained Limit (HSL) of each Resource; and

(B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.

(iii) Other constraints –

(A) Linked offers – the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour, provided that linked Energy and Off-Line Non-Spinning Reserve (Non-Spin) Resource-Specific Ancillary Service Offers are not awarded in the same Operating Hour.

(B) The sum of the awarded Resource-Specific Ancillary Service Offer capacities for each Resource must be within the Resource limits specified in the Current Operating Plan (COP) and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource Parameters as described in Section 3.7, Resource Parameters.

(C) Block Resource-Specific Ancillary Service Offers for a Load Resource – blocks will not be cleared unless the entire quantity block can be awarded. Because block Resource-Specific Ancillary Service Offers cannot set the Market Clearing Price for Capacity (MCPC), a block Ancillary Service Offer may clear below the Ancillary Service Offer price for that block.

(D) Block DAM Energy Bids, DAM Energy-Only Offers, and PTP Obligation bids – blocks will not be cleared unless the entire time and/or quantity block can be awarded. Because quantity block bids and offers cannot set the Settlement Point Price, a quantity block bid or offer may clear in a manner inconsistent with the bid or offer price for that block.

(E) Combined Cycle Generation Resources – The DAM may commit a Combined Cycle Generation Resource in a time period that includes the last hour of the Operating Day only if that Combined Cycle Generation Resource can transition to a shutdown condition in the DAM Operating Day.

(F) Energy Storage Resources (ESRs) – The energy cleared for an ESR may be negative, indicating purchase of energy, or positive, indicating sale of energy.

(d) Ancillary Service needs will be reflected in ASDCs for each Ancillary Service. Self-Arranged Ancillary Service Quantities will first be used to meet the ASDCs, and the remaining Ancillary Service needs are met from Ancillary Service Offers, as long as the costs do not exceed the ASDC value. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service.

(5) ERCOT shall determine the appropriate Load distribution factors to allocate offers, bids, and source and sink of CRRs at a Load Zone across the energized power flow buses that are modeled with Load in that Load Zone. The non-Private Use Network Load distribution factors are based on historical State Estimator hourly distribution using a proxy day methodology representing anticipated weather conditions. The Private Use Network Load distribution factors are based on an estimated Load value considering historical net consumption at all Private Use Networks. If ERCOT decides, in its sole discretion, to change the Load distribution factors for reasons such as anticipated weather events or holidays, ERCOT shall select a State Estimator hourly distribution from a proxy day reasonably reflecting the anticipated Load in the Operating Day. ERCOT may also modify the Load distribution factors to account for predicted differences in network topology between the proxy day and Operating Day. ERCOT shall develop a

methodology, subject to Technical Advisory Committee (TAC) approval, to describe the modification of the proxy day bus-load distribution for this purpose.

[NPRR1004: Replace paragraph (5) above with the following upon system implementation:]

(5) ERCOT shall determine the appropriate Load distribution factors to allocate offers, bids, and source and sink of PTP Obligations at a Load Zone across the energized power flow buses that are modeled with Load in that Load Zone. ERCOT shall derive DAM Load distribution factors with the set of Load distribution factors constructed in accordance with the ERCOT Load distribution factor methodology specified in paragraph (c) of Section 3.12, Load Forecasting. In the event the Load distribution factors are not available, the Load distribution factors for the most recent preceding Operating Day will be used.

(6) ERCOT shall allocate offers, bids, and source and sink of CRRs at a Hub using the distribution factors specified in the definition of that Hub in Section 3.5.2, Hub Definitions.

(7) A Resource that has a Three-Part Supply Offer cleared in the DAM may be eligible for Make-Whole Payment of the Startup Offer and Minimum Energy Offer submitted by the Qualified Scheduling Entity (QSE) representing the Resource under Section 4.6, DAM Settlement.

(8) The DAM Settlement is based on hourly MW awards and on Day-Ahead hourly Settlement Point Prices. All PTP Options settled in the DAM are settled based on the Day-Ahead Settlement Point Prices (DASPPs). ERCOT shall assign a Locational Marginal Price (LMP) to de-energized Electrical Buses for use in the calculation of the DASPPs by using heuristic rules applied in the following order:

(a) Use an appropriate LMP predetermined by ERCOT as applicable to a specific Electrical Bus; or if not so specified

(b) Use the following rules in order:

(i) Use average LMP for Electrical Buses within the same station having the same voltage level as the de-energized Electrical Bus, if any exist.

(ii) Use average LMP for all Electrical Buses within the same station, if any exist.

(iii) Use System Lambda.

(9) The Day-Ahead MCPC for each hour for each Ancillary Service is the Shadow Price for that Ancillary Service for the hour as determined by the DAM algorithm.

(10) Day-Ahead MCPCs shall not exceed the System-Wide Offer Cap (SWCAP). Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in Appendix 2, Day-Ahead Market Optimization Control Parameters, of the Other Binding Document titled "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints," will not be awarded.

[NPRR1080: Delete paragraph (10) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly.]

(11) If the Day-Ahead MCPC cannot be calculated by ERCOT, the Day-Ahead MCPC for the particular Ancillary Service is equal to the Day-Ahead MCPC for that Ancillary Service in the same Settlement Interval of the preceding Operating Day.

[NPRR1008 and NPR1014: Delete paragraph (11) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly.]

(12) If the DASPPs cannot be calculated by ERCOT, all CRRs shall be settled based on Real-Time prices. Settlements for all CRRs shall be reflected on the Real-Time Settlement Statement.

(13) Constraints can exist between the generator's Resource Connectivity Node and the Resource Node, in which case the awarded quantity of energy may be inconsistent with the clearing price when the constraint between the Resource Connectivity Node and the Resource Node is binding.

[NPRR1014: Replace paragraph (13) above with the following upon system implementation:]

(13) Constraints can exist between a Resource's Resource Connectivity Node and its Resource Node, in which case the awarded quantity of energy may be inconsistent with the clearing price when the constraint between the Resource Connectivity Node and the Resource Node is binding.

(14) PTP Obligation bids shall not be awarded where the DAM clearing price for the PTP Obligation is greater than the PTP Obligation bid price plus $0.01/MW per hour.

4.5.2 Ancillary Service Insufficiency

(1) ERCOT shall determine if there is an insufficiency in Ancillary Service Offers. If ERCOT receives insufficient Ancillary Service Offers in the DAM to procure one or more required Ancillary Service such that the Ancillary Service Plan is deficient and system security and reliability is threatened:

(a) ERCOT shall declare an Ancillary Service insufficiency and issue a Watch under Section 6.5.9.3.3, Watch.

(b) ERCOT shall request additional Ancillary Service Offers.

(i) A QSE may resubmit an offer for an Ancillary Service that it submitted before the Watch for the same Ancillary Service quantity block, but the resubmitted offer must meet the following criteria to be considered a valid offer:

(A) The offer quantity may not be less than the offer quantity submitted before the Watch, unless the resubmitted offer quantity is priced lower than the offer quantity submitted before the Watch; and

(B) For the amount of the offer quantity that is equal to or greater than the offer quantity submitted before the Watch, the offer must be priced equal to or less than the price of the offer submitted before the Watch.

(ii) A QSE may submit an offer for an additional Ancillary Service quantity block that was not submitted before the Watch. The incremental amount of the offer may be submitted at a price subject to the offer cap, provided the offer quantity of the Ancillary Service block from paragraph (i) above is not less than the offer quantity submitted before the Watch.

(iii) A QSE that did not submit an Ancillary Service Offer prior to the Watch may submit a new Ancillary Service Offer at a price subject to the offer cap.

(c) ERCOT shall not begin executing the DAM sooner than 30 minutes after issuing the Watch. If the additional Ancillary Service Offers are still insufficient to supply the Ancillary Service required in the Day-Ahead Ancillary Service Plan, then ERCOT shall run the DAM by reducing the Ancillary Service Plan quantities only for purposes of the DAM by the amount of insufficiency.

(d) When ERCOT must reduce the Ancillary Service Plan for purposes of the DAM due to insufficient Ancillary Service Offers, ERCOT shall preserve the Ancillary Service Plan in the DAM in the following order of priority:

(i) Regulation Up (Reg-Up);

(ii) Regulation Down (Reg-Down);

(iii) Responsive Reserve (RRS); and

[NPRR863: Insert paragraph (iv) below upon system implementation and renumber accordingly:]

(iv) ERCOT Contingency Reserve Service (ECRS); and

(iv) Non-Spin.

(2) ERCOT shall procure the difference in capacity between the Day-Ahead Ancillary Service Plan and the DAM-reduced Ancillary Service Plan amounts using the Supplemental Ancillary Service Market (SASM) process in accordance with Section 6.4.9.2.2, SASM Clearing Process. If the SASM process is insufficient, then ERCOT may acquire the insufficient amount of Ancillary Services from Hourly Reliability Unit Commitment (HRUC) Resources that are qualified to provide the needed Ancillary Service. ERCOT may also issue a Watch and procure Ancillary Services in accordance with Section 6.5.9.3.3.

[NPRR1008: Delete Section 4.5.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

4.5.3 Communicating DAM Results

(1) As soon as practicable, but no later than 1330 in the Day-Ahead, ERCOT shall notify the parties to each cleared DAM transaction (e.g., the buyer and the seller) of the results of the DAM as follows:

(a) Awarded Ancillary Service Offers, specifying Resource, MW, Ancillary Service type, and price, for each hour of the awarded offer;

(b) Awarded energy offers from Three-Part Supply Offers and from DAM Energy-Only Offers, specifying Resource (except for DAM Energy-Only Offers), MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded offer;

(c) Awarded DAM Energy Bids, specifying MWh, Settlement Point, and Settlement Point Price for each hour of the awarded bid; and

(d) Awarded PTP Obligation Bids, number of PTP Obligations in MW, source and sink Settlement Points, and price for each Settlement Interval of the awarded bid.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(1) As soon as practicable, but no later than 1330 in the Day-Ahead, ERCOT shall notify the parties to each cleared DAM transaction (e.g., the buyer and the seller) of the results of the DAM as follows:

(a) Awarded Resource-Specific Ancillary Service Offers, specifying Resource, MW, Ancillary Service type, and price, for each hour of the awarded offer;

(b) Awarded Ancillary Service Only Offers, specifying MW, Ancillary Service type, and price, for each hour of the awarded offer;

(c) Awarded energy offers from Three-Part Supply Offers and from DAM Energy-Only Offers, specifying Resource (except for DAM Energy-Only Offers), MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded offer;

(d) Awarded DAM Energy Bids, specifying MWh, Settlement Point, and Settlement Point Price for each hour of the awarded bid;

(e) Awarded Energy Bid/Offer Curves, specifying Resource, MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded bid/offer; and

(f) Awarded PTP Obligation Bids, number of PTP Obligations in MW, source and sink Settlement Points, and price for each Settlement Interval of the awarded bid.

(2) As soon as practicable, but no later than 1330, ERCOT shall post on the ERCOT website the hourly:

(a) Day-Ahead MCPC for each type of Ancillary Service for each hour of the Operating Day;

(b) DASPPs for each Settlement Point for each hour of the Operating Day;

(c) Day-Ahead hourly LMPs for each Electrical Bus for each hour of the Operating Day;

(d) Shadow Prices for every binding constraint for each hour of the Operating Day;

(e) Quantity of total Ancillary Service Offers received in the DAM, in MW by Ancillary Service type for each hour of the Operating Day;

(f) Energy bought in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Bids (in MWh) bought in the DAM at each Settlement Point for each hour of the Operating Day; and

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that sink at each Settlement Point for each hour of the Operating Day.

(g) Energy sold in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Offers (in MWh), from Three-Part Supply Offers and DAM Energy Only Offers, bought in the DAM at each Settlement Point for each hour of the Operating Day; and

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that source at each Settlement Point for each hour of the Operating Day.

(h) Aggregated Ancillary Service Offer Curve of all Ancillary Service Offers for each type of Ancillary Service for each hour of the Operating Day;

(i) Electrically Similar Settlement Points used during the DAM clearing process; and

(j) Settlement Points that were de-energized in the base case; and

(k) System Lambda.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(2) As soon as practicable, but no later than 1330, ERCOT shall post on the ERCOT website the hourly:

(a) Day-Ahead MCPC for each type of Ancillary Service for each hour of the Operating Day;

(b) DASPPs for each Settlement Point for each hour of the Operating Day;

(c) Day-Ahead hourly LMPs for each Electrical Bus for each hour of the Operating Day;

(d) Shadow Prices for every binding constraint for each hour of the Operating Day;

(e) Energy bought in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Bids (in MWh) bought in the DAM at each Settlement Point for each hour of the Operating Day;

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that sink at each Settlement Point for each hour of the Operating Day; and

(iii) The total absolute value quantity of awards to bid portions of Energy Bid/Offer Curves (in MWh) cleared in the DAM at each Settlement Point for each hour of the Operating Day.

(f) Energy sold in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Offers (in MWh), from Three-Part Supply Offers and DAM Energy Only Offers, bought in the DAM at each Settlement Point for each hour of the Operating Day;

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that source at each Settlement Point for each hour of the Operating Day; and

(iii) The total quantity of awards to offer portions of Energy Bid/Offer Curves (in MWh) cleared in the DAM at each Settlement Point for each hour of the Operating Day.

(g) Aggregated Ancillary Service Offer Curve of all Ancillary Service Offers (including both Resource-Specific Ancillary Service Offers and Ancillary Service Only Offers) for each type of Ancillary Service for each hour of the Operating Day;

(h) Electrically Similar Settlement Points used during the DAM clearing process;

(i) Settlement Points that were de-energized in the base case;

(j) System Lambda; and

(k) Ancillary Services sold in the DAM consisting of the total quantity of awarded Resource-Specific Ancillary Service Offers and Ancillary Service Only Offers, for each Ancillary Service for each hour of the Operating Day.

(3) ERCOT shall monitor Day-Ahead MCPCs and Day-Ahead hourly LMPs for errors and if there are conditions that cause the price to be questionable, ERCOT shall notify all Market Participants that the DAM prices are under investigation as soon as practicable.

(4) ERCOT shall correct prices for an Operating Day when a market solution is determined to be invalid or invalid prices are identified in an otherwise valid market solution, accurate prices can be determined, and the impact of the price correction is significant. The following are some reasons that may cause an invalid market solution or invalid prices in a valid market solution.

(a) Data Input error: Missing, incomplete, or incorrect versions of one or more data elements input to the DAM application may result in an invalid market solution and/or prices.

(b) Software error: Pricing errors may occur due to software implementation errors in DAM pre-processing, DAM clearing process, and/or DAM post processing.

(c) Inconsistency with these Protocols or the Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.

(5) For purposes of a price correction performed prior to 1000 on the second Business Day after the Operating Day, the impact of a price correction is considered significant, as that term is used in paragraph (4) above, for the Operating Day when:

(a) The absolute value change to any single DAM Settlement Point Price at a Resource Node or Day-Ahead MCPC is greater than $0.05/MWh;

(b) The price correction would require ERCOT to change more than ten DAM Settlement Point Prices and Day-Ahead MCPCs; or

(c) The absolute value change to any DAM Settlement Point Price at a Load Zone or Hub is greater than $0.02/MWh.

(6) All DAM LMPs, MCPCs, and Settlement Point Prices are final at 1000 of the second Business Day after the Operating Day.

(a) However, after DAM LMPs, MCPCs, and Settlement Point Prices are final, if ERCOT determines that prices qualify for a correction pursuant to paragraph (4) above and that ERCOT will seek ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT’s duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT’s authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT’s authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

(b) Before seeking ERCOT Board review of prices, ERCOT will determine if the impact of the price correction is significant, as that term is used in paragraph (4) above, by calculating the potential changes to the DAM Settlement Statement(s) of any Counter-Party on the given Operating Day. ERCOT shall seek ERCOT Board review of prices if the change in DAM Settlement Statement(s) would result in the absolute value impact to any single Counter-Party, based on the sum of all original DAM Settlement Statement amounts of Market Participants assigned to the Counter-Party, to be greater than:

(i) 2% and also greater than $20,000; or

(ii) 20% and also greater than $2,000.

(c) The ERCOT Board may review and change DAM LMPs, MCPCs, or Settlement Point Prices if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices should be corrected for an Operating Day.

(d) In review of DAM LMPs, MCPCs, or Settlement Point Prices, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices should be corrected for an Operating Day.

(7) As soon as practicable, but no later than 1330, ERCOT shall make available the Day-Ahead Shift Factors for binding constraints in the DAM and post to the Market Information System (MIS) Secure Area.

4.6 DAM Settlement

4.6.1 Day-Ahead Settlement Point Prices

(1) The Day-Ahead Settlement Point Price (DASPP) calculations are described in this Section for Resource Nodes, Load Zones, Hubs, and logical Resource Nodes.

4.6.1.1 Day-Ahead Settlement Point Prices for Resource Nodes

(1) The DASPP for a Resource Node Settlement Point for an hour is the Locational Marginal Price (LMP) at that Resource Node for that hour as calculated in the Day-Ahead Market (DAM) process.

4.6.1.2 Day-Ahead Settlement Point Prices for Load Zones

(1) The DASPP for a Load Zone Settlement Point for an hour is calculated as follows:

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

$$\mathbf{DASPP} = \mathbf{DASL} - \sum_{c} (\mathbf{DALZSF}_{c} * \mathbf{DASP}_{c})$$

Where:

$$\text{DALZSF}_{c} = \sum_{pb} (\text{DADF}_{pb,\,c} * \text{DASF}_{pb,\,c})$$

$$\text{DADF}_{pb,\,c} = \text{DAL}_{pb,\,c} / (\sum_{pb} \text{DAL}_{pb,\,c})$$

For a DC Tie Load Zone:

$$\mathbf{DASPP} = \mathbf{DALMP}_{b}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DASPP	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Load Zone, for the hour.
DALMP $_{b}$	\$/MWh	*Day-Ahead Locational Marginal Price per bus*—The DAM LMP at Electrical Bus *b* for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DALZSF $_{c}$	none	*Day-Ahead Shift factor of the Load Zone* —The DAM aggregated Shift Factor of a Load Zone for the constraint *c* for the hour.
DASF $_{pb,\,,c}$	none	*Day-Ahead Shift factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of the Load Zone for the constraint *c* for the hour.
DADF $_{pb,\,c}$	none	*Day-Ahead Distribution factor per power flow bus for a constraint*—The Load distribution factor for power flow bus *pb* in the Load Zone for the constraint *c* for the hour.
DAL $_{pb,\,c}$	MW	*Day-Ahead Load at power flow bus for a constraint*—The DAM distributed load for power flow bus *pb* in the Load Zone for the constraint *c* for the hour.
b	none	An Electrical Bus that is assigned to the DC Tie Load Zone.
pb	none	An energized power flow bus that is assigned to the Load Zone for the constraint *c*.
c	None	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

4.6.1.3 Day-Ahead Settlement Point Prices for Hubs

(1) The DASPP for a Settlement Point at a Hub is determined according to the methodology included in the definition of that Hub in Section 3.5, Hubs.

4.6.1.4 Day-Ahead Settlement Point Prices at the Logical Resource Node for a

Combined Cycle Generation Resource

(1) ERCOT shall calculate the DASPP for each hour at the logical Resource Node for the Combined Cycle Generation Resource as follows:

(a) The DASPP at a logical Resource Node shall be the sum of a weight factor as determined in paragraph (b) below times the Day-Ahead LMP at each of the Resource Nodes of the generation units registered in the Combined Cycle Train registration for the Combined Cycle Generation Resource designated in the Three-Part Supply Offer:

Where:

$$\text{DASPP} = \sum_{\text{CCGR\_PhyR}} \text{DALMP}_{\text{CCGR\_PhyR}} * \text{DACCGRWF}_{\text{CCGR\_PhyR}}$$

The above variables are defined as follows:

Variable	Unit	Definition
DASPP	\$/MWh	*Day-Ahead Settlement Point Price at a logical Resource Node for a Combined Cycle Train*—The DAM Settlement Point Price at the logical Resource Node for a Combined Cycle Generation Resource for the hour.
$\text{DALMP}_{\text{CCGR\_PhyR}}$	\$/MWh	*Day-Ahead Locational Marginal Price at a Resource Node for a generation unit registered in the Combined Cycle Generation Resource*—The Day-Ahead LMP at the Resource Node of a generation unit designated in the Combined Cycle Train registration for the Combined Cycle Generation Resource.
$\text{DACCGRWF}_{\text{CCGR\_PhyR}}$	none	*Day-Ahead Combined Cycle Generation Resource Weighting Factor*—The DAM Combined Cycle Generation Resource weighting factor for a generation unit designated in a Combined Cycle Train registration for the Combined Cycle Generation Resource.
CCGR_PhyR	none	A generation unit designated in a Combine Cycle Train for the Combined Cycle Generation Resource.

(b) The weight factor for each generation unit designated in the Combined Cycle Train registration for the Combined Cycle Generation Resource shall be the generation unit's High Reasonability Limit (HRL), as specified in the Resource Registration data provided to ERCOT pursuant to Planning Guide Section 6.8.2, Resource Registration Process, divided by the total of all HRL values for the generation units designated in the Combined Cycle Generation Resource Registration data.

Where:

$$\mathbf{DACCGRWF}_{\boldsymbol{CCGR\_PhyR}} = \mathbf{HRL}_{\boldsymbol{CCGR\_PhyR}} / \sum_{\boldsymbol{CCGR\_PhyR}} \mathbf{HRL}_{\boldsymbol{CCGR\_PhyR}}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DACCGRWF}_{\text{CCGR\_PhyR}}$	none	*Day-Ahead Combined Cycle Generation Resource Weighting Factor*—The DAM Combined Cycle Generation Resource weighting factor for a

		generation unit designated in a Combined Cycle Train registration for the Combined Cycle Generation Resource.
HRL $_{CCGR\_PhyR}$	MW	*High Reasonability Limit*—The HRL as specified in the ERCOT-approved Resource Registration data for a generation unit designated in a Combined Cycle Train registration for the Combined Cycle Generation Resource.
CCGR_PhyR	none	A generation unit designated in a Combined Cycle Train for the Combined Cycle Generation Resource.

4.6.2 Day-Ahead Energy and Make-Whole Settlement

4.6.2.1 Day-Ahead Energy Payment

(1) The Day-Ahead Energy Payment is made for all cleared offers to sell energy in the DAM, whether through Three-Part Supply Offers or DAM Energy-Only Offer Curves. The payment to each Qualified Scheduling Entity (QSE) for each Settlement Point for a given hour of the Operating Day is calculated as follows:

$$\text{DAESAMT}_{q,\,p} \quad = \quad (-1) * \text{DASPP}_{p} * \text{DAES}_{q,\,p}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DAESAMT $_{q,\,p}$	$	*Day-Ahead Energy Sale Amount per QSE per Settlement Point*—The payment to QSE *q* for the cleared energy offers at Settlement Point *p* for the hour.
DASPP $_{p}$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM SPP at Settlement Point *p* for the hour.
DAES $_{q,\,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves at Settlement Point *p*, for the hour.
q	none	A QSE.
p	none	A Settlement Point.

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

(1) The Day-Ahead Energy Payment is made for all cleared offers to sell energy in the DAM, whether through Three-Part Supply Offers, DAM Energy-Only Offer Curves, or cleared sales from the offer portion of Energy Bid/Offer Curves. The payment to each Qualified Scheduling Entity (QSE) for each Settlement Point for a given hour of the Operating Day is calculated as follows:

$$\text{DAESAMT}_{q,\,p} \quad = \quad (-1) * \text{DASPP}_{p} * \text{DAES}_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DAESAMT_{q,\,p}$	$	*Day-Ahead Energy Sale Amount per QSE per Settlement Point*—The payment to QSE *q* for the cleared energy offers at Settlement Point *p* for the hour.
$DASPP_{p}$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM SPP at Settlement Point *p* for the hour.
$DAES_{q,\,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared Three-Part Supply Offers in the DAM, cleared DAM Energy-Only Offer Curves, and cleared sales from the offer portion of Energy Bid/Offer Curves at Settlement Point *p*, for the hour.
q	none	A QSE.
p	none	A Settlement Point.

(2) The total of the Day-Ahead Energy Payments to each QSE for the hour is calculated as follows:

$$DAESAMTQSETOT_{q} = \sum_{p} DAESAMT_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DAESAMTQSETOT_{q}$	$	*Day-Ahead Energy Sale Amount QSE Total per QSE*—The total of the payments to QSE *q* for its cleared energy offers at all Settlement Points for the hour.
$DAESAMT_{q,\,p}$	$	*Day-Ahead Energy Sale Amount per QSE per Settlement Point*—The payment to QSE *q* for the cleared energy offers at Settlement Point *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.

4.6.2.2 Day-Ahead Energy Charge

(1) The Day-Ahead Energy Charge is made for all cleared DAM Energy Bids. This charge to each QSE for each Settlement Point for a given hour of the Operating Day is calculated as follows:

$$DAEPAMT_{q,\,p} = DASPP_{p} * DAEP_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DAEPAMT_{q,\,p}$	$	*Day-Ahead Energy Charge per QSE per Settlement Point*—The charge to QSE *q* for all its cleared DAM Energy Bids at Settlement Point *p* for the hour.
$DASPP_{p}$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM SPP at Settlement Point *p* for the hour.

Variable	Unit	Definition
DAEP $_{q,\,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared DAM Energy Bids at Settlement Point *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.

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

(1) The Day-Ahead Energy Charge is made for all cleared DAM Energy Bids or cleared purchases from the bid portion of Energy Bid/Offer Curves. This charge to each QSE for each Settlement Point for a given hour of the Operating Day is calculated as follows:

$$\text{DAEPAMT}_{q,\,p} \quad = \quad \text{DASPP}_{p} * \text{DAEP}_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAEPAMT $_{q,\,p}$	$	*Day-Ahead Energy Charge per QSE per Settlement Point*—The charge to QSE *q* for all its cleared energy bids at Settlement Point *p* for the hour.
DASPP $_{p}$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM SPP at Settlement Point *p* for the hour.
DAEP $_{q,\,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared DAM Energy Bids and cleared purchases from the bid portion of Energy Bid/Offer Curves at Settlement Point *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.

(2) The total of the Day-Ahead Energy Charges to each QSE for the hour is calculated as follows:

$$\text{DAEPAMTQSETOT}_{q} \quad = \quad \sum_{p} \text{DAEPAMT}_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAEPAMTQSETOT $_{q}$	$	*Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total of the charges to QSE *q* for its cleared DAM Energy Bids at all Settlement Points for the hour.
DAEPAMT $_{q,\,p}$	$	*Day-Ahead Energy Purchase Amount per QSE per Settlement Point*—The charge to QSE *q* for its cleared DAM Energy Bids at Settlement Point *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.

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

(2) The total of the Day-Ahead Energy Charges to each QSE for the hour is calculated as follows:

$$\text{DAEPAMTQSETOT}_{q} = \sum_{p} \text{DAEPAMT}_{q,\,p}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DAEPAMTQSETOT $_{q}$	\$	*Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total of the charges to QSE *q* for its cleared energy bids at all Settlement Points for the hour.
DAEPAMT $_{q,\,p}$	\$	*Day-Ahead Energy Purchase Amount per QSE per Settlement Point*—The charge to QSE *q* for its cleared DAM Energy Bids and cleared purchases from the bid portion of Energy Bid/Offer Curves at Settlement Point *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.

4.6.2.3 Day-Ahead Make-Whole Settlements

(1) A QSE that has a Three-Part Supply Offer cleared in the DAM is eligible for a Day-Ahead Make-Whole Payment startup cost compensation, if, for the Resource associated with the offer:

(a) The generator's breakers were open, as indicated by a telemetered Resource status of Off-Line, for at least five minutes during the Adjustment Period for the beginning of the DAM commitment;

(b) The generator's breakers were closed, as indicated by a telemetered Resource status of On-Line, for at least one minute during the DAM commitment period; and

(c) The breaker open-close sequence, as indicated by the On-Line/Off-Line sequence from the telemetered Resource status, for which the QSE is eligible for startup cost compensation in the DAM or Reliability Unit Commitment (RUC) for the previous Operating Day does not qualify in meeting the criteria in items (a) and (b) above.

(d) The breaker open-close sequence for which the QSE is eligible for startup cost compensation in an earlier DAM commitment period within the same Operating Day does not qualify in meeting the criteria in items (a) and (b) above.

(2) Notwithstanding the eligibility criteria described in paragraph (1) above, a Resource will not be eligible for Day-Ahead Make-Whole Payment Startup Cost compensation if the Resource was considered by the DAM as not having a cost to start due to the DAM commitment period being contiguous with a self-committed hour, as described in Section 4.4.9.1, Three-Part Supply Offers.

(3) A QSE that has a Three-Part Supply Offer cleared in the DAM is eligible for Day-Ahead Make-Whole Payment energy cost compensation in a DAM-committed Operating Hour, if, for the Resource associated with the offer the generator's breakers were closed, as indicated by a telemetered Resource Status of On-Line, for at least one minute during the DAM-committed Operating Hour.

(4) The Day-Ahead Make-Whole Payment guarantees the QSE that the total payment received from the DAM for a DAM-committed Resource is not less than the total cost calculated based on the Startup Cap, the Minimum Energy Cap, and the Energy Offer Curve capped by the Energy Offer Curve Cap defined under Section 4.4.9.3.3, Energy Offer Curve Cost Caps.

(5) If a Generation Resource is eligible for startup or energy cost compensation in the Day-Ahead Make-Whole payment, then Ancillary Service revenue from the hours committed in the DAM will be included in its make-whole calculation for that Resource.

(6) For purposes of this Section 4.6.2.3, the telemetered Resource Status of OFFQS shall be considered as Off-Line.

[NPRR1014: Insert paragraph (7) below upon system implementation:]

(7) An Energy Storage Resource (ESR) is not eligible for Day-Ahead Make-Whole Payment.

4.6.2.3.1 Day-Ahead Make-Whole Payment

(1) ERCOT shall pay the QSE a Day-Ahead Make-Whole Payment for an eligible Resource for each Operating Hour in a DAM-commitment period.

(2) Any Ancillary Service Offer cleared for the same Operating Hour, QSE, and Generation Resource as a Three-Part Supply Offer cleared in the DAM shall be included in the calculation of the Day-Ahead Make-Whole Payment.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) Any Resource-Specific Ancillary Service Offer cleared for the same Operating Hour, QSE, and Generation Resource as a Three-Part Supply Offer cleared in the DAM shall be included in the calculation of the Day-Ahead Make-Whole Payment.

(3) The guaranteed cost, energy revenue, and Ancillary Service revenue calculated for each Combined Cycle Generation Resource are each summed for the Combined Cycle Train, and the the Day-Ahead Make-Whole Amount is calculated for the Combined Cycle Train.

(4) For an Aggregate Generation Resource (AGR), Startup Cost shall be scaled according to the ratio of the maximum number of its generators online during a contiguous block of DAM-committed Intervals, as indicated by telemetry, compared to the total number of generators registered to the AGR and used in the approved verifiable cost for the AGR.

(5) The Day-Ahead Make-Whole Payment to each QSE for each DAM-committed Generation Resource is calculated as follows:

$$\text{DAMWAMT}_{q,\,p,\,r,\,h} = (-1) * \text{Max}\,(0, \text{DAMGCOST}_{q,\,p,\,r} + \sum_{h} \text{DAEREV}_{q,\,p,\,r,\,h} + \sum_{h} \text{DAASREV}_{q,\,r,\,h}) * \text{DAESR}_{q,\,p,\,r,\,h} \,/\, (\sum_{h} \text{DAESR}_{q,\,p,\,r,\,h})$$

(6) The Day-Ahead Make-Whole Guaranteed Costs are calculated for each eligible DAM-Committed Generation Resource as follows:

For non-Combined Cycle Trains,

$$\text{DAMGCOST}_{q,\,p,\,r} = \text{Min}(\text{DASUO}_{q,\,p,\,r}\,, \text{DASUCAP}_{q,\,p,\,r}) + \sum_{h} (\text{Min}(\text{DAMEO}_{q,\,p,\,r,\,h}\,, \text{DAMECAP}_{p\,,q,\,r\,,h})* \text{DALSL}_{q,\,p,\,r,\,h}) + \sum_{h} (\text{DAAIEC}_{q,\,p,\,r,\,h} * (\text{DAESR}_{q,\,p,\,r,\,h} - \text{DALSL}_{q,\,p,\,r,\,h}))$$

For a Resource which is not an AGR,

If ERCOT has approved verifiable Startup Costs and minimum-energy costs for the Resource,

Then: $\text{DASUCAP}_{p,q,\,r}$ = verifiable Startup Costs $_{q,\,r,\,s}$

$\text{DAMECAP}_{p,q,r,h}$ = verifiable minimum-energy costs $_{q,\,r,\,i}$

Otherwise: $\text{DASUCAP}_{p,q,\,r}$ = Resource Category Startup Offer Generic Cap (RCGSC)

$\text{DAMECAP}_{p,q,\,r,\,h}$ = Resource Category Minimum-Energy Generic Cap (RCGMEC)

For an AGR,

$$\mathrm{DAMGCOST}_{q,\,p,\,r} = \mathrm{DASUPR}_{q,\,p,\,r} + \sum_{h} (\mathrm{Min}(\mathrm{DAMEO}_{q,\,p,\,r,\,h}, \mathrm{DAMECAP}_{p,q,r,h}) * \mathrm{DALSL}_{q,\,p,\,r,\,h}) + \sum_{h} (\mathrm{DAAIEC}_{q,\,p,\,r,\,h} * (\mathrm{DAESR}_{q,\,p,\,r,\,h} - \mathrm{DALSL}_{q,\,p,\,r,\,h}))$$

Where:

$$\mathrm{DASUPR}_{q,\,p,\,r} = \mathrm{Min}(\mathrm{DASUO}_{q,\,p,\,r}, \mathrm{DASUCAP}_{q,\,p,\,r})$$

If ERCOT has approved verifiable Startup Costs

Then: $\mathrm{DASUCAP}_{q,\,p,\,r} = \mathrm{Max}_{c}(\mathrm{AGRRATIO}_{q,\,p,\,r}) * \text{verifiable Startup Costs}_{q,\,r}$

Where: $\mathrm{AGRRATIO}_{q,\,p,\,r} = \mathrm{AGRMAXON}_{q,\,p,\,r} / \mathrm{AGRTOT}_{q,\,p,\,r}$

Otherwise: $\mathrm{DASUCAP}_{q,\,p,\,r} = \mathrm{Max}_{c}(\mathrm{AGGRATIO}_{q,p,r}) * \mathrm{RCGSC}$

For Combined Cycle Trains,

$$\mathrm{DAMGCOST}_{q,\,p,\,r} = \mathrm{Min}(\mathrm{DASUO}_{q,\,p,\,r}, \mathrm{DASUCAP}_{q,\,p,\,r}) + \sum_{h} (\mathrm{Min}(\mathrm{DAMEO}_{q,\,p,\,r,\,h}, \mathrm{DAMECAP}_{q,\,p,\,r,h}) * \mathrm{DALSL}_{q,\,p,\,r,\,h}) + (\mathrm{Max}(0, \mathrm{Min}(\mathrm{DASUO}_{afterCCGR}, \mathrm{DASUCAP}_{afterCCGR}) - \mathrm{Min}(\mathrm{DASUO}_{beforeCCGR}, \mathrm{DASUCAP}_{beforeCCGR})) + \sum_{h} (\mathrm{DAAIEC}_{q,\,p,\,r,\,h} * (\mathrm{DAESR}_{q,\,p,\,r,\,h} - \mathrm{DALSL}_{q,\,p,\,r,\,h}))$$

(7) The Day-Ahead Make-Whole Revenue is calculated for each DAM-Committed Generation Resource as follows:

$$\mathrm{DAEREV}_{q,\,p,\,r,\,h} = (-1) * \mathrm{DASPP}_{p,\,h} * \mathrm{DAESR}_{q,\,p,\,r,\,h}$$

$$\begin{aligned}\mathrm{DAASREV}_{q,\,r,\,h} = {} & ((-1) * \mathrm{MCPCRU}_{DAM,\,h} * \mathrm{PCRUR}_{r,\,q,\,DAM,\,h}) \\ & + ((-1) * \mathrm{MCPCRD}_{DAM,\,h} * \mathrm{PCRDR}_{r,\,q,DAM,\,h}) \\ & + ((-1) * \mathrm{MCPCRR}_{DAM,\,h} * \mathrm{PCRRR}_{r,\,q,DAM,\,h}) \\ & +((-1) * \mathrm{MCPCNS}_{DAM,\,h} * \mathrm{PCNSR}_{r,\,q,DAM,\,h})\end{aligned}$$

[NPRR863: Replace the formula "DAASREV $_{q,\,r,\,h}$***" above with the following upon system implementation:]***

$$\begin{aligned}\mathrm{DAASREV}_{q,\,r,\,h} = {} & ((-1) * \mathrm{MCPCRU}_{DAM,\,h} * \mathrm{PCRUR}_{r,\,q,\,DAM,\,h}) \\ & + ((-1) * \mathrm{MCPCRD}_{DAM,\,h} * \mathrm{PCRDR}_{r,\,q,\,DAM,\,h})\end{aligned}$$

$$+ ((-1) * \text{MCPCECR}_{\,DAM,\,h} * \text{PCECRR}_{\,r,\,q,\,DAM,\,h})$$

$$+ ((-1) * \text{MCPCNS}_{\,DAM,\,h} * \text{PCNSR}_{\,r,\,q,\,DAM,\,h})$$

$$+ ((-1) * \text{MCPCRR}_{\,DAM,\,h} * \text{PCRRR}_{\,r,\,q,\,DAM,\,h})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DAMWAMT $_{q,\,p,\,r,\,h}$	$	*Day-Ahead Make-Whole Payment per QSE per Settlement Point per Resource per hour*—The payment to QSE *q* to make-whole the Startup Cost and energy cost of Resource *r* committed in the DAM at Resource Node *p* for the hour *h*. When a Combined Cycle Generation Resource is committed in the DAM, payment is made to the Combined Cycle Train for the DAM-committed Combined Cycle Generation Resource.
DAMGCOST $_{q,\,p,\,r}$	$	*Day-Ahead Market Guaranteed Amount per QSE per Settlement Point per Resource*—The sum of the Startup Cost and the operating energy costs of the DAM-committed Resource *r* at Resource Node *p* represented by QSE *q*, for the DAM-commitment period. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DAEREV $_{q,\,p,\,r,\,h}$	$	*Day-Ahead Energy Revenue per QSE per Settlement Point per Resource by hour*—The revenue received in the DAM for Resource *r* at Resource Node *p* represented by QSE *q*, based on the DAM Settlement Point Price, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DAASREV $_{q,\,r,\,h}$	$	*Day-Ahead Ancillary Service Revenue per QSE per Resource by hour*—The revenue received in the DAM for Resource *r* represented by QSE *q*, based on the Market Clearing Price for Capacity (MCPC) for each Ancillary Service in the DAM, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DASPP $_{p,\,h}$	$/MWh	*Day-Ahead Settlement Point Price by Settlement Point by hour*—The DAM Settlement Point Price at Resource Node *p* for the hour *h*.
DAESR $_{q,\,p,\,r,\,h}$	MW	*Day-Ahead Energy Sale from Resource per QSE by Settlement Point per Resource by hour*—The amount of energy cleared through Three-Part Supply Offers in the DAM for Resource *r* at Resource Node *p* represented by QSE *q* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DASUPR $_{q,\,p,\,r}$	$/MWh	*Day-Ahead Startup Price per QSE per Settlement Point per Resource*—The derived Startup Price for an AGR *r* at Resource Node *p* represented by QSE *q*, for the first hour of the DAM-commitment period.
DASUCAP $_{q,\,p,\,r,}$	$/start	*Day-Ahead Startup Cap per QSE per Settlement Point per Resource*—The amount used for AGR *r* or Resource *r* as Startup Costs. The cap is the Resource Category Startup Offer Generic Cap (RCGSC) unless ERCOT has approved verifiable unit-specific Startup Costs for that Resource, in which case the startup cap is the scaled verifiable unit-specific Startup Cost for the AGR or the verifiable unit-specific Startup Cost for non-AGR Resources. See Section 5.6.1, Verifiable Costs, for more information on verifiable costs.

Variable	Unit	Definition
$\text{DAMECAP}_{p,q,r,h}$	\$/MWh	*Day-Ahead Minimum-Energy Cap* —The amount used for Resource *r* for minimum-energy costs. The minimum cost is the Resource Category Minimum-Energy Generic Cap (RCGMEC) unless ERCOT has approved verifiable unit-specific minimum energy costs for that Resource, in which case the minimum energy cap is the verifiable unit-specific minimum energy cost. See Section 5.6.1 for more information on verifiable costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RCGSC	\$/Start	*Resource Category Generic Startup Cost*—The Resource Category Generic Startup Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$\text{PCRUR}_{r,\ q,\ DAM,\ h}$	MW	*Procured Capacity for Reg-Up from Resource per Resource per QSE per hour in DAM*—The Regulation Up (Reg-Up) capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{MCPCRU}_{DAM,\ h}$	\$/MW per hour	*Market Clearing Price for Capacity for Reg-Up per hour in DAM*—The DAM MCPC for Reg-Up for the hour *h*.
$\text{PCRDR}_{r,\ q,\ DAM,\ h}$	MW	*Procured Capacity for Reg-Down from Resource per Resource per QSE per hour in DAM*—The Regulation Down (Reg-Down) capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{MCPCRD}_{DAM,\ h}$	\$/MW per hour	*Market Clearing Price for Capacity for Reg-Down per hour in DAM*—The DAM MCPC for Reg-Down for the hour *h*.
$\text{PCRRR}_{r,\ q,\ DAM,\ h}$	MW	*Procured Capacity for Responsive Reserve from Resource per Resource per QSE per hour in DAM*—The Responsive Reserve (RRS) capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{MCPCRR}_{DAM,\ h}$	\$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per hour in DAM*—The DAM MCPC for RRS for the hour *h*.
$\text{PCNSR}_{r,\ q,\ DAM,\ h}$	MW	*Procured Capacity for Non-Spin from Resource per Resource per QSE per hour in DAM*—The Non-Spinning Reserve (Non-Spin) capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

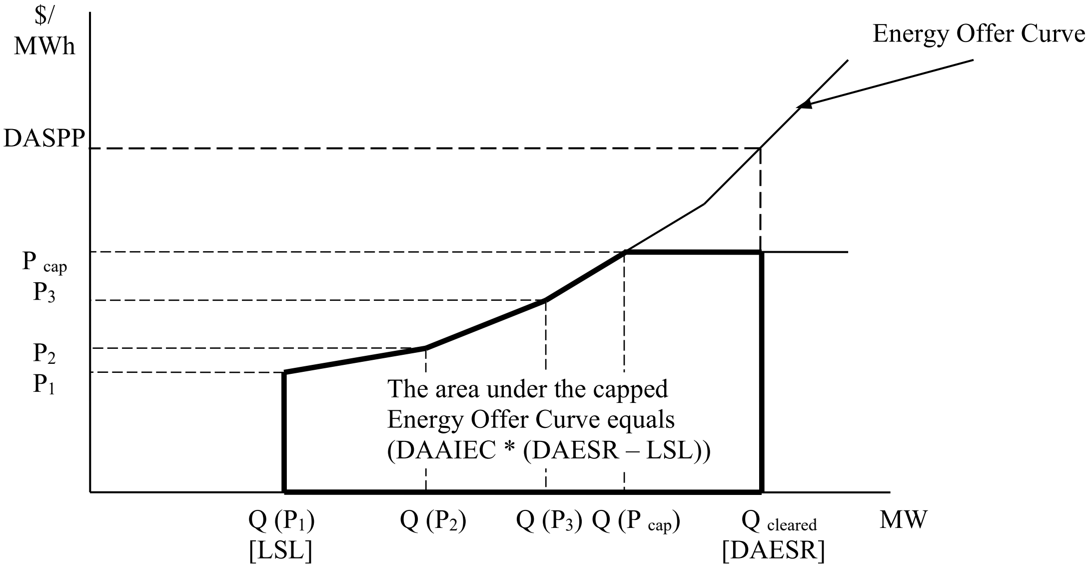
[NPRR863: Insert the variables “PCECRR $_{r,\ q,\ DAM,\ h}$” and “MCPCECR $_{DAM,\ h}$” below upon system implementation:]

$\text{PCECRR}_{r,\ q,\ DAM,\ h}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service from Resource per Resource per QSE per hour in DAM*—The ERCOT Contingency Reserve Service (ECRS) capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{MCPCECR}_{DAM,\ h}$	\$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per hour in DAM*—The DAM MCPC for ECRS for the hour *h*.

Variable	Unit	Definition
$\text{MCPCNS}_{\mathit{DAM, h}}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin per hour in DAM*—The DAM MCPC for Non-Spin for the hour *h*. ***[NPRR1008: Replace the description above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]*** *Market Clearing Price for Capacity for Non-Spin per hour*—The DAM MCPC for Non-Spin for the hour *h*.
$\text{DASUO}_{q, p, r}$	$/start	*Day-Ahead Startup Offer per QSE per Settlement Point per Resource*—The Startup Offer included in the Three-Part Supply Offer submitted in the DAM associated with Resource *r* at Resource Node *p* represented by QSE *q*, for the first hour of the DAM-commitment period. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{AGRRATIO}_{q, p, r}$	none	*Aggregate Generation Resource Ratio per QSE per Settlement Point per Aggregate Generation Resource*—A value which represents the ratio of the maximum number of generators online in an hour, as indicated by telemetry, compared to the total number of generators registered to the AGR and used in the approved verifiable cost for the AGR. The value is only applicable if the Resource is an AGR.
$\text{AGRMAXON}_{q, p, r}$	none	*Aggregate Generation Resource Maximum Online per QSE per Settlement Point per Aggregate Generation Resource*—The maximum number of generators online during an hour, as indicated by telemetry. The value is only applicable if the Resource is an AGR.
$\text{AGRTOT}_{q, p, r}$	none	*Aggregate Generation Resource Total per QSE per Settlement Point per Aggregate Generation Resource*—The total number of generators registered to the AGR and used in the approved verifiable cost for the AGR. The value is only applicable if the Resource is an AGR.
$\text{DAMEO}_{q, p, r, h}$	$/MWh	*Day-Ahead Minimum-Energy Offer per QSE per Settlement Point per Resource per hour*—The Minimum-Energy Offer included in the Three-Part Supply Offer submitted in the DAM associated with Resource *r* at Resource Node *p* represented by QSE *q*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{DALSL}_{q, p, r, h}$	MW	*Day-Ahead Low Sustained Limit per QSE per Settlement Point per Resource per hour*—The Low Sustained Limit (LSL) of Resource *r* at Resource Node *p* represented by QSE *q*, for the hour *h* as seen in the 1000 Day-Ahead snapshot. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{DAAIEC}_{q, p, r\ h}$	$/MWh	*Day-Ahead Average Incremental Energy Cost per QSE per Settlement Point per Resource per hour*—The average incremental energy cost, calculated according to the Energy Offer Curve capped by the generic energy price, for the output levels between the DAESR and the LSL of Resource *r* at Resource Node *p* represented by QSE *q*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A DAM-committed Generation Resource.
h	none	An hour in the DAM-commitment period.

Variable	Unit	Definition
c	none	A contiguous block of DAM-committed hours.
afterCCGR	none	The Combined Cycle Generation Resource to which a Combined Cycle Train transitions.
beforeCCGR	none	The Combined Cycle Generation Resource from which a Combined Cycle Train transitions.

(8) The calculation of the Day-Ahead Average Incremental Energy Cost for each Resource for each hour is illustrated with the picture below, where P_{cap} is the Energy Offer Curve Cap. The method to calculate such cost is described in Section 4.6.5, Calculation of "Average Incremental Energy Cost" (AIEC).



(9) The total of the Day-Ahead Make-Whole Payments to each QSE for Generation Resources for a given hour is calculated as follows:

$$\text{DAMWAMTQSETOT}_{q} = \sum_{p} \sum_{r} \text{DAMWAMT}_{q, p, r}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAMWAMTQSETOT $_{q}$	$	*Day-Ahead Make-Whole Payment QSE Total per QSE*—The total of the Day-Ahead Make-Whole Payments to QSE *q* for the DAM-committed Generation Resources represented by this QSE for the hour.
DAMWAMT $_{q, p, r}$	$	*Day-Ahead Make-Whole Payment per QSE per Settlement Point per Resource*—The payment to QSE *q* to make-whole the Startup Cost and energy cost of Resource *r* committed in the DAM at Resource Node *p* for the hour. When a Combined Cycle Generation Resource is committed in the DAM, payment is made to the Combined Cycle Train for the DAM-committed Combined Cycle Generation Resource.
q	none	A QSE.

Variable	Unit	Definition
p	none	A Settlement Point.
r	none	A DAM-committed Generation Resource.

4.6.2.3.2 Day-Ahead Make-Whole Charge

(1) ERCOT shall charge a Day-Ahead Make-Whole Charge to each QSE that has one or more cleared DAM Energy Bids and/or Point-to-Point (PTP) Obligation Bids. The Day-Ahead Make-Whole Charge for an hour is that QSE's prorata share of the total amount of Day-Ahead Make-Whole Payments for that hour. The proration must be based on the ratio of the energy amount of the QSE's cleared DAM Energy Bids and PTP Obligation Bids to the total energy amount of all QSEs' cleared DAM Energy Bids and PTP Obligation Bids. The Day-Ahead Make-Whole Charge to each QSE for a given hour is calculated as follows:

$$\text{LADAMWAMT}_{q} = (-1) * \text{DAMWAMTTOT} * \text{DAERS}_{q}$$

Where:

Day-Ahead Make-Whole Payment Total

$$\text{DAMWAMTTOT} = \sum_{q} \text{DAMWAMTQSETOT}_{q}$$

Day-Ahead Energy Purchase Ratio Share per QSE

$$\text{DAERS}_{q} = \text{DAE}_{q} / \text{DAETOT}$$

$$\text{DAETOT} = \sum_{q} \text{DAE}_{q}$$

$$\text{DAE}_{q} = \sum_{p} \text{DAEP}_{q,\,p} + \sum_{j} \sum_{k} \text{RTOBL}_{q,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
LADAMWAMT_{q}	$	*Day-Ahead Make-Whole Charge*—The allocated charge to QSE q to make whole all the eligible DAM-committed Resources for the hour.
DAMWAMTTOT	$	*Day-Ahead Make-Whole Payment Total*—The total of the Day-Ahead Make-Whole Payments to all QSEs for all DAM-committed Resources for the hour.
DAMWAMTQSETOT_{q}	$	*Day-Ahead Make-Whole Payment QSE Total per QSE*—The total of the Day-Ahead Make-Whole Payments to QSE q for the DAM-committed Generation Resources represented by this QSE for the hour.
DAERS_{q}	none	*Day-Ahead Energy Purchase Ratio Share per QSE*— The ratio of QSE q's total amount of energy represented by its cleared DAM Energy Bids and PTP Obligation Bids, to the total amount of energy represented by all QSEs' cleared DAM Energy Bids and PTP Obligation Bids, for the hour.

Variable	Unit	Definition
DAETOT	MW	*Day-Ahead Energy Total*—The total amount of energy represented by all cleared DAM Energy Bids and all cleared PTP Obligation Bids for the hour.
DAE $_{q}$	MW	*Day-Ahead Energy per QSE*—QSE *q*'s total amount of energy, represented by its cleared DAM Energy Bids and PTP Obligation Bids, for the hour.
DAEP $_{q,\,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared DAM Energy Bids at the Settlement Point *p* for the hour.
RTOBL $_{q,\,(j,\,k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total amount of energy represented by QSE *q*'s cleared PTP Obligation Bids with the source *j* and the sink *k*, for the hour.
q	none	A QSE.
p	none	A Settlement Point.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

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

(1) ERCOT shall charge a Day-Ahead Make-Whole Charge to each QSE that has one or more cleared DAM Energy Bids, cleared purchases from the bid portion of Energy Bid/Offer Curves, and/or Point-to-Point (PTP) Obligation Bids. The Day-Ahead Make-Whole Charge for an hour is that QSE's prorata share of the total amount of Day-Ahead Make-Whole Payments for that hour. The proration must be based on the ratio of the energy amount of the QSE's cleared DAM Energy Bids, cleared purchases from the bid portion of Energy Bid/Offer Curves, and PTP Obligation Bids to the total energy amount of all QSEs' cleared DAM Energy Bids, cleared purchases from the bid portion of Energy Bid/Offer Curves, and PTP Obligation Bids. The Day-Ahead Make-Whole Charge to each QSE for a given hour is calculated as follows:

$$\text{LADAMWAMT}_{q} = (-1) * \text{DAMWAMTTOT} * \text{DAERS}_{q}$$

Where:

Day-Ahead Make-Whole Payment Total

$$\text{DAMWAMTTOT} = \sum_{q} \text{DAMWAMTQSETOT}_{q}$$

Day-Ahead Energy Purchase Ratio Share per QSE

$$\text{DAERS}_{q} = \text{DAE}_{q} / \text{DAETOT}$$

$$\text{DAETOT} = \sum_{q} \text{DAE}_{q}$$

$$\text{DAE}_{q} = \sum_{p} \text{DAEP}_{q,\,p} + \sum_{j} \sum_{k} \text{RTOBL}_{q,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LADAMWAMT_{q}	$	*Day-Ahead Make-Whole Charge*—The allocated charge to QSE *q* to make whole all the eligible DAM-committed Resources for the hour.
DAMWAMTTOT	$	*Day-Ahead Make-Whole Payment Total*—The total of the Day-Ahead Make-Whole Payments to all QSEs for all DAM-committed Resources for the hour.
DAMWAMTQSETOT_{q}	$	*Day-Ahead Make-Whole Payment QSE Total per QSE*—The total of the Day-Ahead Make-Whole Payments to QSE *q* for the DAM-committed Generation Resources represented by this QSE for the hour.
DAERS_{q}	none	*Day-Ahead Energy Purchase Ratio Share per QSE*— The ratio of QSE *q*'s total amount of energy represented by its cleared DAM Energy Bids, cleared purchases from the bid portion of Energy Bid/Offer Curves, and PTP Obligation Bids, to the total amount of energy represented by all QSEs' cleared DAM Energy Bids, cleared purchases from the bid portion of Energy Bid/Offer Curves, and PTP Obligation Bids, for the hour.
DAETOT	MW	*Day-Ahead Energy Total*—The total amount of energy represented by all cleared DAM Energy Bids, all cleared purchases from the bid portion of Energy Bid/Offer Curves, and all cleared PTP Obligation Bids for the hour.
DAE_{q}	MW	*Day-Ahead Energy per QSE*—QSE *q*'s total amount of energy, represented by its cleared DAM Energy Bids, cleared purchases from the bid portion of Energy Bid/Offer Curves, and PTP Obligation Bids, for the hour.
$\text{DAEP}_{q,\,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared DAM Energy Bids and cleared purchases from the bid portion of Energy Bid/Offer Curves at the Settlement Point *p* for the hour.
$\text{RTOBL}_{q,\,(j,\,k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total amount of energy represented by QSE *q*'s cleared PTP Obligation Bids with the source *j* and the sink *k*, for the hour.
q	none	A QSE.
p	none	A Settlement Point.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

4.6.3 Settlement for PTP Obligations Bought in DAM

(1) ERCOT shall pay or charge a QSE for a cleared PTP Obligation bid the difference in the DAM Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The charge or payment to each QSE for a given Operating Hour of its cleared PTP Obligation bids with each pair of source and sink Settlement Points is calculated as follows:

$$\text{DARTOBLAMT}_{q,\,(j,\,k)} \quad = \quad \text{DAOBLPR}_{(j,\,k)} * \text{RTOBL}_{q,\,(j,\,k)}$$

Where:

$$\text{DAOBLPR}_{(j,\,k)} = \text{DASPP}_{k} - \text{DASPP}_{j}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DARTOBLAMT $_{q,\,(j,\,k)}$	$	*Day-Ahead Real-Time Obligation Amount per QSE per pair of source and sink*—The charge or payment to QSE *q* for a PTP Obligation bid cleared in the DAM with the source *j* and the sink *k*, for the hour.
DAOBLPR $_{(j,\,k)}$	$/MWh	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation bid with the source *j* and the sink *k*, for the hour.
DASPP $_{j}$	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j* for the hour.
DASPP $_{k}$	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k* for the hour.
RTOBL $_{q,\,(j,\,k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k,* for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(2) The net total charge or payment to the QSE for the hour of all its cleared PTP Obligation bids is calculated as follows:

$$\text{DARTOBLAMTQSETOT}_{q} \quad = \quad \sum_{j} \sum_{k} \text{DARTOBLAMT}_{q,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DARTOBLAMTQSETOT$_{\text{q}}$	$	*Day-Ahead Real-Time Obligation Amount QSE Total per QSE*—The net total charge or payment to QSE *q* for all its PTP Obligation bids cleared in the DAM for the hour.
DARTOBLAMT $_{\text{q, (j, k)}}$	$	*Day-Ahead Real-Time Obligation Amount per QSE per pair of source and sink*—The charge or payment to QSE *q* for a PTP Obligation bids cleared in the DAM with the source *j* and the sink *k*, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(3) ERCOT shall charge a QSE for a cleared PTP Obligation bid with Links to an Option the positive difference in the DASPP between the sink Settlement Point and the source Settlement Point. The charge to each QSE for a given Operating Hour of its cleared PTP Obligation bid with Links to an Option with each pair of source and sink Settlement Points is calculated as follows:

$$\text{DARTOBLLOAMT}_{q,\,(j,\,k)} = \text{Max}\,(0, \text{DAOBLPR}_{(j,\,k)})\ ^{*}\ \text{RTOBLLO}_{q,\,(j,\,k)}$$

Where:

$$\text{RTOBLLO}_{q,\,(j,\,k)} = \sum_{crrid} \text{OBLLOCRR}_{q,\,(j,\,k),\,crrid,\,crrofferid}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARTOBLLOAMT $_{q,\,(j,\,k)}$	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount per QSE per pair of source and sink*—The charge to QSE *q* for a PTP Obligation bid with Links to an Option cleared in the DAM with the source *j* and the sink *k*, for the hour.
DAOBLPR $_{(j,\,k)}$	$/MWh	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation bid with the source *j* and the sink *k*, for the hour.
RTOBLLO $_{q,\,(j,\,k)}$	MW	*Real-Time PTP Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids with Links to an Option cleared in the DAM and settled in Real-Time for the source *j* and the sink *k,* for the hour.
OBLLOCRR $_{q,\,(j,\,k),\,crrid,\,crrofferid}$	MW	*PTP Obligation with Links to an Option per QSE per pair of source and sink, CRRID and CRR Offer ID of the linked Option*—The total MW of QSE *q*'s PTP Obligation bids with Links to an Option cleared in the DAM for the source *j* and the sink *k,* for the hour and CRRID and CRROFFERID of the linked PTP Option.
crrid	none	A Congestion Revenue Right (CRR) Option identification code.
crrofferid	none	A CRR Offer identification code.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(4) The net total charge to the QSE for the hour of all its cleared PTP Obligation bids with Links to an Option is calculated as follows:

$$\text{DARTOBLLOAMTQSETOT}_{q} = \sum_{j} \sum_{k} \text{DARTOBLLOAMT}_{q,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARTOBLLOAMTQSETOT $_{q}$	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The net total charge to QSE *q* for all its PTP Obligation bids with Links to an Option cleared in the DAM for the hour.
DARTOBLLOAMT $_{q,\,(j,\,k)}$	$	*Day-Ahead Real-Time Obligation with Links to Option Amount per QSE per pair of source and sink*—The charge to QSE *q* for a PTP Obligation bid with Links to an Option cleared in the DAM with the source *j* and the sink *k*, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.

k	none	A sink Settlement Point.

4.6.4 Settlement of Ancillary Services Procured in the DAM

(1) ERCOT shall pay each QSE providing Ancillary Services procured in the DAM the amount of Ancillary Service Capacity in MW procured from the QSE multiplied by the MCPC for the Ancillary Service provided, expressed in \$/MW. Each QSE shall pay for its share of each Ancillary Service procured by ERCOT in the DAM.

4.6.4.1 Payments for Ancillary Services Procured in the DAM

4.6.4.1.1 Regulation Up Service Payment

(1) ERCOT shall pay each QSE whose Ancillary Service Offers to provide Reg-Up to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCRUAMT}_{q} \quad = \quad (-1) * \text{MCPCRU}_{DAM} * \text{PCRU}_{q}$$

Where:

$$\text{PCRU}_{q} \quad = \quad \sum_{r} \text{PCRUR}_{r,\, q,\, DAM}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
PCRUAMT_{q}	\$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q* for the hour.
PCRU_{q}	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$\text{PCRUR}_{r,\, q,\, DAM}$	MW	*Procured Capacity for Reg-Up from Resource per Resource per QSE in DAM*—The Reg-Up capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRU_{DAM}	\$/MW per hour	*Market Clearing Price for Capacity for Reg-Up in DAM*—The DAM MCPC for Reg-Up for the hour.
r	none	A Resource.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall pay each QSE whose Resource-Specific Ancillary Service Offers to provide Reg-Up to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCRUAMT}_{q} = (-1) * \text{MCPCRU}_{DAM} * \text{PCRU}_{q}$$

Where:

$$\text{PCRU}_{q} = \sum_{r} \text{PCRUR}_{r,\,q,\,DAM}$$

(2) ERCOT shall pay each QSE whose Ancillary Service Only Offers to provide Reg-Up to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{DAPCRUOAMT}_{q} = (-1) * \text{MCPCRU}_{DAM} * \text{DARUOAWD}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
PCRUAMT_{q}	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q* for the hour.
DAPCRUOAMT_{q}	$	*Day-Ahead Procured Capacity for Reg-Up Only Amount per QSE*—The payment to QSE *q* for all Reg-Up only awards in DAM for the hour.
PCRU_{q}	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$\text{PCRUR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for Reg-Up from Resource per Resource per QSE in DAM*—The Reg-Up capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRU_{DAM}	$/MW	*Market Clearing Price for Capacity for Reg-Up in DAM*—The DAM MCPC for Reg-Up for the hour.
DARUOAWD_{q}	MW	*Day-Ahead Reg-Up Only Award per QSE* —The Reg-Up Only capacity quantity awarded in DAM to QSE *q* for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.1.2 Regulation Down Service Payment

(1) ERCOT shall pay each QSE whose Ancillary Service Offers to provide Reg-Down to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCRDAMT}_{q} = (-1) * \text{MCPCRD}_{DAM} * \text{PCRD}_{q}$$

Where:

$$\text{PCRD}_{q} = \sum_{r} \text{PCRDR}_{r,\,q,\,DAM}$$

The above variables are defined as follows:

Variable	Unit	Definition
$PCRDAMT_{q}$	\$	*Procured Capacity for Reg-Down Amount per QSE in DAM*—The DAM Reg-Down payment for QSE *q* for the hour.
$PCRD_{q}$	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$PCRDR_{r, q, DAM}$	MW	*Procured Capacity for Reg-Down from Resource per Resource per QSE in DAM*—The Reg-Down capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$MCPCRD_{DAM}$	\$/MW per hour	*Market Clearing Price for Capacity for Reg-Down in DAM*—The DAM MCPC for Reg-Down for the hour.
r	none	A Resource.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall pay each QSE whose Resource-Specific Ancillary Service Offers to provide Reg-Down to ERCOT were cleared in the DAM, for each hour as follows:

$$PCRDAMT_{q} \quad = \quad (-1) * MCPCRD_{DAM} * PCRD_{q}$$

Where:

$$PCRD_{q} \quad = \quad \sum_{r} PCRDR_{r, q, DAM}$$

(2) ERCOT shall pay each QSE whose Ancillary Service Only Offers to provide Reg-Down to ERCOT were cleared in the DAM, for each hour as follows:

$$DAPCRDOAMT_{q} = (-1) * MCPCRD_{DAM} * DARDOAWD_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$PCRDAMT_{q}$	\$	*Procured Capacity for Reg-Down Amount per QSE in DAM*—The DAM Reg-Down payment for QSE *q* for the hour.
$DAPCRDOAMT_{q}$	\$	*Day-Ahead Procured Capacity for Reg-Down Only Amount per QSE*— The payment to QSE *q* for all Reg-Down only awards in DAM for the hour.
$PCRD_{q}$	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$PCRDR_{r, q, DAM}$	MW	*Procured Capacity for Reg-Down from Resource per Resource per QSE in DAM*—The Reg-Down capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

MCPCRD_{DAM}	\$/MW	*Market Clearing Price for Capacity for Reg-Down in DAM*—The DAM MCPC for Reg-Down for the hour.
DARDOAWD_q	MW	*Day-Ahead Reg-Down Only Award per QSE* —The Reg-Down only capacity quantity awarded in DAM to QSE *q* for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.1.3 Responsive Reserve Payment

(1) ERCOT shall pay each QSE whose Ancillary Service Offers to provide RRS to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCRRAMT}_q = (-1) * \text{MCPCRR}_{DAM} * \text{PCRR}_q$$

Where:

$$\text{PCRR}_q = \sum_r \text{PCRRR}_{r,\,q,\,DAM}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
PCRRAMT_q	\$	*Procured Capacity for Responsive Reserve Amount per QSE in DAM*—The DAM RRS payment for QSE *q* for the hour.
PCRR_q	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total RRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$\text{PCRRR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for Responsive Reserve from Resource per Resource per QSE in DAM*—The RRS capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRR_{DAM}	\$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for RRS for the hour.
r	none	A Resource.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall pay each QSE whose Resource-Specific Ancillary Service Offers to provide RRS to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCRRAMT}_q = (-1) * \text{MCPCRR}_{DAM} * \text{PCRR}_q$$

Where:

$$\text{PCRR}_{q} = \sum_{r} \text{PCRRR}_{r,\, q,\, DAM}$$

(2) ERCOT shall pay each QSE whose Ancillary Service Only Offers to provide RRS to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{DAPCRROAMT}_{q} = (-1) * \text{MCPCRR}_{DAM} * \text{DARROAWD}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
PCRRAMT_{q}	$	*Procured Capacity for Responsive Reserve Amount per QSE in DAM*—The DAM RRS payment for QSE *q* for the hour.
DAPCRROAMT_{q}	$	*Day-Ahead Procured Capacity for Responsive Reserve Only Amount per QSE*— The payment to QSE *q* for all RRS only awards in DAM for the hour.
PCRR_{q}	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total RRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$\text{PCRRR}_{r,\, q,\, DAM}$	MW	*Procured Capacity for Responsive Reserve from Resource per Resource per QSE in DAM*—The RRS capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRR_{DAM}	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for RRS for the hour.
DARROAWD_{q}	MW	*Day-Ahead Responsive Reserve Only Award per QSE* —The RRS only capacity quantity awarded in DAM to QSE *q* for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.1.4 Non-Spinning Reserve Service Payment

(1) ERCOT shall pay each QSE whose Ancillary Service Offers to provide Non-Spin to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCNSAMT}_{q} = (-1) * \text{MCPCNS}_{DAM} * \text{PCNS}_{q}$$

Where:

$$\text{PCNS}_{q} = \sum_{r} \text{PCNSR}_{r,\, q,\, DAM}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
PCNSAMT_{q}	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
PCNS_{q}	MW	*Procured Capacity for Non-Spin per QSE in DAM*—The total Non-Spin Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.

PCNSR $_{r,\ q,\ DAM}$	MW	*Procured Capacity for Non-Spin from Resource per Resource per QSE in DAM*—The Non-Spin capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCNS $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin in DAM*—The DAM MCPC for Non-Spin for the hour.
r	none	A Resource.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall pay each QSE whose Resource-Specific Ancillary Service Offers to provide Non-Spin to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCNSAMT}_{q} \quad = \quad (-1) * \text{MCPCNS}_{DAM} * \text{PCNS}_{q}$$

Where:

$$\text{PCNS}_{q} \quad = \quad \sum_{r} \text{PCNSR}_{r,\ q,\ DAM}$$

(2) ERCOT shall pay each QSE whose Ancillary Service Only Offers to provide Non-Spin to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{DAPCNSOAMT}_{q} = (-1) * \text{MCPCNS}_{DAM} * \text{DANSOAWD}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
PCNSAMT $_{q}$	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
DAPCNSOAMT $_{q}$	$	*Day-Ahead Procured Capacity for Non-Spin Only Amount per QSE*— The payment to QSE *q* for all Non-Spin only awards in DAM for the hour.
PCNS $_{q}$	MW	*Procured Capacity for Non-Spin per QSE in DAM*—The total Non-Spin Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
PCNSR $_{r,\ q,\ DAM}$	MW	*Procured Capacity for Non-Spin from Resource per Resource per QSE in DAM*—The Non-Spin capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCNS $_{DAM}$	$/MW	*Market Clearing Price for Capacity for Non-Spin in DAM*—The DAM MCPC for Non-Spin for the hour.
DANSOAWD $_{q}$	MW	*Day-Ahead Non-Spin Only Award per QSE* —The Non-Spin only capacity quantity awarded in DAM to QSE *q* for the hour.
r	none	A Resource.
q	none	A QSE.

[NPRR863 and NPRR1008: Insert applicable portions of Section 4.6.4.1.5 below upon system implementation or upon system implementation of the Real-Time Co-Optimization (RTC) project, respectively:]

4.6.4.1.5 ERCOT Contingency Reserve Service Payment

(1) ERCOT shall pay each QSE whose Resource-Specific Ancillary Service Offers to provide ECRS to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{PCECRAMT}_{q} \quad = \quad (-1) * \text{MCPCECR}_{DAM} * \text{PCECR}_{q}$$

Where:

$$\text{PCECR}_{q} \quad = \quad \sum_{r} \text{PCECRR}_{r,\,q,\,DAM}$$

(2) ERCOT shall pay each QSE whose Ancillary Service Only Offers to provide ECRS to ERCOT were cleared in the DAM, for each hour as follows:

$$\text{DAPCECROAMT}_{q} = (-1) * \text{MCPCECR}_{DAM} * \text{DAECROAWD}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
PCECRAMT_{q}	$	*Procured Capacity for ERCOT Contingency Reserve Service Amount per QSE in DAM*—The DAM ECRS payment for QSE *q* for the hour.
DAPCECROAMT_{q}	$	*Day-Ahead Procured Capacity for ERCOT Contingency Reserve Service Only Amount per QSE*— The payment to QSE *q* for all ECRS only awards in DAM for the hour.
PCECR_{q}	MW	*Procured Capacity for ERCOT Contingency Reserve Service per QSE in DAM*—The total ECRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$\text{PCECRR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service from Resource per Resource per QSE in DAM*—The ECRS capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCECR_{DAM}	$/MW	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service in DAM*—The DAM MCPC for ECRS for the hour.
DAECROAWD_{q}	MW	*Day-Ahead ERCOT Contingency Reserve Service Only Award per QSE* — The ECRS only capacity quantity awarded in DAM to QSE *q* for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.2 Charges for Ancillary Services Procurement in the DAM

4.6.4.2.1 Regulation Up Service Charge

(1) Each QSE shall pay to ERCOT or be paid by ERCOT a Reg-Up Service charge for each hour as follows:

$$\text{DARUAMT}_q = \text{DARUPR} * \text{DARUQ}_q$$

Where:

$$\text{DARUPR} = (-1) * \text{PCRUAMTTOT} / \text{DARUQTOT}$$

$$\text{PCRUAMTTOT} = \sum_q \text{PCRUAMT}_q$$

$$\text{DARUQTOT} = \sum_q \text{DARUQ}_q$$

$$\text{DARUQ}_q = \text{DARUO}_q - \text{DASARUQ}_q$$

The above variables are defined as follows:

Variable	Unit	Definition
DARUAMT_q	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Up, for the hour.
DARUPR	$/MW per hour	*Day-Ahead Reg-Up Price*—The Day-Ahead Reg-Up price for the hour.
DARUQ_q	MW	*Day-Ahead Reg-Up Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Up quantity for the hour.
PCRUAMTTOT	$	*Procured Capacity for Reg-Up Amount Total in DAM*—The total of the DAM Reg-Up payments for all QSEs for the hour.
PCRUAMT_q	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q* for the hour.
DARUQTOT	MW	*Day-Ahead Reg-Up Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Up quantity for the hour.
DARUO_q	MW	*Day-Ahead Reg-Up Obligation per QSE*—The Reg-Up capacity obligation for QSE *q* for the DAM for the hour.
DASARUQ_q	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) Each QSE shall pay to ERCOT or be paid by ERCOT a Reg-Up Service charge for each hour as follows:

$$\text{DARUAMT}_q = \text{DARUPR} * \text{DARUQ}_q$$

Where:

$$\text{DARUPR} = (-1) * \text{DAPCRUAMTTOT} / \text{DARUQTOT}$$

$$\text{DAPCRUAMTTOT} = \sum_q (\text{PCRUAMT}_q + \text{DAPCRUOAMT}_q)$$

$$\text{DARUQTOT} = \sum_q \text{DARUQ}_q$$

$$\text{DARUQ}_q = \text{DARUO}_q - \text{DASARUQ}_q$$

The above variables are defined as follows:

Variable	Unit	Definition
DARUAMT_q	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Up, for the hour.
DARUPR	$/MW	*Day-Ahead Reg-Up Price*—The Day-Ahead Reg-Up price for the hour.
DARUQ_q	MW	*Day-Ahead Reg-Up Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Up quantity for the hour.
DAPCRUAMTTOT	$	*Day-Ahead Procured Capacity for Reg-Up Amount Total* —The total of the DAM Reg-Up payments for all QSEs for the hour.
PCRUAMT_q	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q* for the hour.
DAPCRUOAMT_q	$	*Day-Ahead Procured Capacity for Reg-Up Only Amount per QSE*—The payment to QSE *q* for all Reg-Up only awards in DAM for the hour.
DARUQTOT	MW	*Day-Ahead Reg-Up Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Up quantity for the hour.
DARUO_q	MW	*Day-Ahead Reg-Up Obligation per QSE*—The Reg-Up capacity obligation for QSE *q* for the DAM for the hour.
DASARUQ_q	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.4.2.2 Regulation Down Service Charge

(1) Each QSE shall pay to ERCOT or be paid by ERCOT a Reg-Down Service charge for each hour as follows:

$$\text{DARDAMT}_q = \text{DARDPR} * \text{DARDQ}_q$$

Where:

$$\text{DARDPR} = (-1) * \text{PCRDAMTTOT} / \text{DARDQTOT}$$

$$\text{PCRDAMTTOT} = \sum_{q} \text{PCRDAMT}_{q}$$

$$\text{DARDQTOT} = \sum_{q} \text{DARDQ}_{q}$$

$$\text{DARDQ}_{q} = \text{DARDO}_{q} - \text{DASARDQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DARDAMT_{q}	$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the hour.
DARDPR	$/MW per hour	*Day-Ahead Reg-Down Price*—The Day-Ahead Reg-Down price for the hour.
DARDQ_{q}	MW	*Day-Ahead Reg-Down Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Down quantity for the hour.
PCRDAMTTOT	$	*Procured Capacity for Reg-Down Amount Total in DAM*—The total of the DAM Reg-Down payments for all QSEs for the hour.
PCRDAMT_{q}	$	*Procured Capacity for Reg-Down Amount per QSE in DAM*—The DAM Reg-Down payment for QSE *q* for the hour.
DARDQTOT	MW	*Day-Ahead Reg-Down Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Down quantity for the hour.
DARDO_{q}	MW	*Day-Ahead Reg-Down Obligation per QSE*—The Reg-Down capacity obligation for QSE *q* for the DAM for the hour.
DASARDQ_{q}	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) Each QSE shall pay to ERCOT or be paid by ERCOT a Reg-Down Service charge for each hour as follows:

$$\text{DARDAMT}_{q} = \text{DARDPR} * \text{DARDQ}_{q}$$

Where:

$$\text{DARDPR} = (-1) * \text{DAPCRDAMTTOT} / \text{DARDQTOT}$$

$$\text{DAPCRDAMTTOT} = \sum_{q} (\text{PCRDAMT}_{q} + \text{DAPCRDOAMT}_{q})$$

$$\text{DARDQTOT} = \sum_{q} \text{DARDQ}_{q}$$

$$\text{DARDQ}_{q} = \text{DARDO}_{q} - \text{DASARDQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARDAMT_{q}	$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the hour.
DARDPR	$/MW	*Day-Ahead Reg-Down Price*—The Day-Ahead Reg-Down price for the hour.
DARDQ_{q}	MW	*Day-Ahead Reg-Down Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Down quantity for the hour.
DAPCRDAMTTOT	$	*Day-Ahead Procured Capacity for Reg-Down Amount Total*—The total of the DAM Reg-Down payments for all QSEs for the hour.
PCRDAMT_{q}	$	*Procured Capacity for Reg-Down Amount per QSE in DAM*—The DAM Reg-Down payment for QSE *q* for the hour.
DAPCRDOAMT_{q}	$	*Day-Ahead Procured Capacity for Reg-Down Only Amount per QSE*—The payment to QSE *q* for all Reg-Down only awards in DAM for the hour.
DARDQTOT	MW	*Day-Ahead Reg-Down Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Down quantity for the hour.
DARDO_{q}	MW	*Day-Ahead Reg-Down Obligation per QSE*—The Reg-Down capacity obligation for QSE *q* for the DAM for the hour.
DASARDQ_{q}	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.4.2.3 Responsive Reserve Charge

(1) Each QSE shall pay to ERCOT or be paid by ERCOT an RRS charge for each hour as follows:

$$\text{DARRAMT}_{q} = \text{DARRPR} * \text{DARRQ}_{q}$$

Where:

$$\text{DARRPR} = (-1) * \text{PCRRAMTTOT} / \text{DARRQTOT}$$

$$\text{PCRRAMTTOT} = \sum_{q} \text{PCRRAMT}_{q}$$

$$\text{DARRQTOT} = \sum_{q} \text{DARRQ}_{q}$$

$$\text{DARRQ}_{q} = \text{DARRO}_{q} - \text{DASARRQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DARRAMT $_q$	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for RRS, for the hour.
DARRPR	$/MW per hour	*Day-Ahead Responsive Reserve Price*—The Day-Ahead RRS price for the hour.
DARRQ $_q$	MW	*Day-Ahead Responsive Reserve Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged RRS quantity for the hour.
PCRRAMTTOT	$	*Procured Capacity for Responsive Reserve Amount Total in DAM*—The total of the DAM RRS payments for all QSEs for the hour.
PCRRAMT $_q$	$	*Procured Capacity for Responsive Reserve Amount per QSE for DAM*—The DAM RRS payment for QSE *q* for the hour.
DARRQTOT	MW	*Day-Ahead Responsive Reserve Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged RRS quantity for the hour.
DARRO $_q$	MW	*Day-Ahead Responsive Reserve Obligation per QSE*—The RRS capacity obligation for QSE *q* for the DAM for the hour.
DASARRQ $_q$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) Each QSE shall pay to ERCOT or be paid by ERCOT an RRS charge for each hour as follows:

$$\text{DARRAMT}_{q} = \text{DARRPR} * \text{DARRQ}_{q}$$

Where:

$$\text{DARRPR} = (-1) * \text{DAPCRRAMTTOT} / \text{DARRQTOT}$$

$$\text{DAPCRRAMTTOT} = \sum_{q} (\text{PCRRAMT}_{q} + \text{DAPCRROAMT}_{q})$$

$$\text{DARRQTOT} = \sum_{q} \text{DARRQ}_{q}$$

$$\text{DARRQ}_{q} = \text{DARRO}_{q} - \text{DASARRQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARRAMT_{q}	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for RRS, for the hour.
DARRPR	$/MW	*Day-Ahead Responsive Reserve Price*—The Day-Ahead RRS price for the hour.
DARRQ_{q}	MW	*Day-Ahead Responsive Reserve Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged RRS quantity for the hour.
DAPCRRAMTTOT	$	*Day-Ahead Procured Capacity for Responsive Reserve Amount Total*—The total of the DAM RRS payments for all QSEs for the hour.
PCRRAMT_{q}	$	*Procured Capacity for Responsive Reserve Amount per QSE for DAM*—The DAM RRS payment for QSE *q* for the hour.
DAPCRROAMT_{q}	$	*Day-Ahead Procured Capacity for Responsive Reserve Only Amount per QSE*— The payment to QSE *q* for all RRS only awards in DAM for the hour.
DARRQTOT	MW	*Day-Ahead Responsive Reserve Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged RRS quantity for the hour.
DARRO_{q}	MW	*Day-Ahead Responsive Reserve Obligation per QSE*—The RRS capacity obligation for QSE *q* for the DAM for the hour.
DASARRQ_{q}	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.4.2.4 Non-Spinning Reserve Service Charge

(1) Each QSE shall pay to ERCOT or be paid by ERCOT a Non-Spin Service charge for each hour as follows:

$$\text{DANSAMT}_{q} = \text{DANSPR} * \text{DANSQ}_{q}$$

Where:

$$\text{DANSPR} = (-1) * \text{PCNSAMTTOT} / \text{DANSQTOT}$$

$$\text{PCNSAMTTOT} = \sum_{q} \text{PCNSAMT}_{q}$$

$$\text{DANSQTOT} = \sum_{q} \text{DANSQ}_{q}$$

$$\text{DANSQ}_{q} = \text{DANSO}_{q} - \text{DASANSQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition

DANSAMT $_q$	$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin, for the hour.
DANSPR	$/MW per hour	*Day-Ahead Non-Spin Price*—The Day-Ahead Non-Spin price for the hour.
DANSQ $_q$	MW	*Day-Ahead Non-Spin Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Non-Spin quantity for the hour.
PCNSAMTTOT	$	*Procured Capacity for Non-Spin Amount Total in DAM*—The total of the DAM Non-Spin payments for all QSEs for the hour.
PCNSAMT $_q$	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
DANSQTOT	MW	*Day-Ahead Non-Spin Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Non-Spin quantity for the hour.
DANSO $_q$	MW	*Day-Ahead Non-Spin Obligation per QSE*—The Non-Spin capacity obligation for QSE *q* for the DAM for the hour.
DASANSQ $_q$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) Each QSE shall pay to ERCOT or be paid by ERCOT a Non-Spin Service charge for each hour as follows:

$$\text{DANSAMT}_q = \text{DANSPR} * \text{DANSQ}_q$$

Where:

$$\text{DANSPR} = (-1) * \text{DAPCNSAMTTOT} / \text{DANSQTOT}$$

$$\text{DAPCNSAMTTOT} = \sum_q (\text{PCNSAMT}_q + \text{DAPCNSOAMT}_q)$$

$$\text{DANSQTOT} = \sum_q \text{DANSQ}_q$$

$$\text{DANSQ}_q = \text{DANSO}_q - \text{DASANSQ}_q$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DANSAMT $_q$	$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin, for the hour.
DANSPR	$/MW	*Day-Ahead Non-Spin Price*—The Day-Ahead Non-Spin price for the hour.

DANSQ $_q$	MW	*Day-Ahead Non-Spin Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Non-Spin quantity for the hour.
DAPCNSAMTTOT	$	*Day-Ahead Procured Capacity for Non-Spin Amount Total*—The total of the DAM Non-Spin payments for all QSEs for the hour.
PCNSAMT $_q$	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
DAPCNSOAMT $_q$	$	*Day-Ahead Procured Capacity for Non-Spin Only Amount per QSE*—The payment to QSE *q* for all Non-Spin only awards in DAM for the hour.
DANSQTOT	MW	*Day-Ahead Non-Spin Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Non-Spin quantity for the hour.
DANSO $_q$	MW	*Day-Ahead Non-Spin Obligation per QSE*—The Non-Spin capacity obligation for QSE *q* for the DAM for the hour.
DASANSQ $_q$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

[NPRR863 and NPRR1008: Insert applicable portions of Section 4.6.4.2.5 below upon system implementation, or upon system implementation of the Real-Time Co-Optimization (RTC) project, respectively:]

4.6.4.2.5 ERCOT Contingency Reserve Service Charge

(1) Each QSE shall pay to ERCOT or be paid by ERCOT an ECRS charge for each hour as follows:

$$\text{DAECRAMT}_q = \text{DAECRPR} * \text{DAECRQ}_q$$

Where:

$$\text{DAECRPR} = (-1) * \text{DAPCECRAMTTOT} / \text{DAECRQTOT}$$

$$\text{DAPCECRAMTTOT} = \sum_q (\text{PCECRAMT}_q + \text{DAPCECROAMT}_q)$$

$$\text{DAECRQTOT} = \sum_q \text{DAECRQ}_q$$

$$\text{DAECRQ}_q = \text{DAECRO}_q - \text{DASAECRQ}_q$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DAECRAMT $_q$	$	*Day-Ahead ERCOT Contingency Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for ECRS, for the hour.

DAECRPR	$/MW	*Day-Ahead ERCOT Contingency Reserve Price*—The Day-Ahead ECRS price for the hour.
DAECRQ $_q$	MW	*Day-Ahead ERCOT Contingency Reserve Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged ECRS quantity for the hour.
DAPCECRAMTTOT	$	*Day-Ahead Procured Capacity for ERCOT Contingency Reserve Amount Total*—The total of the DAM ECRS payments for all QSEs for the hour.
PCECRAMT $_q$	$	*Procured Capacity for ERCOT Contingency Reserve Amount per QSE for DAM*—The DAM ECRS payment for QSE *q* for the hour.
DAPCECROAMT $_q$	$	*Day-Ahead Procured Capacity for ERCOT Contingency Reserve Service Only Amount per QSE*— The payment to QSE *q* for all ECRS only awards in DAM for the hour.
DAECRQTOT	MW	*Day-Ahead ERCOT Contingency Reserve Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged ECRS quantity for the hour.
DAECRO $_q$	MW	*Day-Ahead ERCOT Contingency Reserve Obligation per QSE*—The ECRS capacity obligation for QSE *q* for the DAM for the hour.
DASAECRQ $_q$	MW	*Day-Ahead Self-Arranged ERCOT Contingency Reserve Quantity per QSE*—The self-arranged ECRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.5 Calculation of "Average Incremental Energy Cost" (AIEC)

(1) The methodology of AIEC calculation is presented below. AIEC is used to account for the additional cost for a Generation Resource to produce energy above its LSL. This cost calculation methodology is used for the calculation of the DAAIEC variable.

I. Energy Offer Curve:

Index (i)	**MW**	**$/MWh**
1	Q_1	P_1
2	Q_2	P_2
⋮	⋮	⋮
N (N≤10)	Q_N	P_N

II. MW quantity corresponding with Energy Offer Curve Cost Cap[1], $\overline{P}$ ($/MWh), where $P_i < \overline{P} \le P_{i+1}$ ($i = 1,2,\cdots,N-1$):

---

[1] If the Energy Offer Curve Cost Cap is less than the lowest price of the energy offer curve, the AIEC is the Energy Offer Curve Cap. If the Energy Offer Curve Cost Cap is greater than the highest price of the energy offer curve, then $\overline{Q}$ does not need to be calculated.

$$\overline{Q} \text{ (MW), where } \overline{Q} = Q_i + \frac{Q_{i+1} - Q_i}{P_{i+1} - P_i}(\overline{P} - P_i)$$

III. Energy Offer Curve capped with the Energy Offer Curve Cost Cap:

A. When $\overline{P} < P_N$:

Index (j)	MW	$/MWh
1	Q_1	P_1
M	M	M
i	Q_i	P_i
i+1	$\overline{Q}$	$\overline{P}$
i+2	Q_N	$\overline{P}$

B. When $\overline{P} \geq P_N$:

Index (j)	MW	$/MWh
1	Q_1	P_1
M	M	M
N	Q_N	P_N

IV. Cleared offer on the capped Energy Offer Curve:

A. When $\overline{P} < P_N$:

$$\text{Q (MW), where } Q_j < Q \leq Q_{j+1} \ (j = 1, \cdots, i, i+1)$$

B. When $\overline{P} \geq P_N$:

$$\text{Q (MW), where } Q_j < Q \leq Q_{j+1} \ (j = 1, \cdots, N-1)$$

V. Incremental energy price corresponding with cleared offer, on the capped Energy Offer Curve or between two points along the Energy Offer Curve:

$$\text{P (\$/MWh), where } P = P_j + \frac{P_{j+1} - P_j}{Q_{j+1} - Q_j}(Q - Q_j)$$

VI. AIEC corresponding with ($Q-Q_1>0$), on the capped Energy Offer Curve:

$$AIEC = \begin{cases} \dfrac{P_1 + P}{2}, \; for \; Q_1 < Q \le Q_2 \\ \left[\displaystyle\sum_{k=1}^{j-1} \dfrac{P_k + P_{k+1}}{2}(Q_{k+1} - Q_k) + \dfrac{P_j + P}{2}(Q - Q_j) \right] \Big/ (Q - Q_1), \; for \; Q > Q_2 \end{cases}$$

ERCOT Nodal Protocols

Section 5: Transmission Security Analysis and Reliability Unit Commitment

December 1, 2022

5 TRANSMISSION SECURITY ANALYSIS AND RELIABILITY UNIT COMMITMENT

5.1 Introduction

(1) Transmission security analysis and Reliability Unit Commitment (RUC) are used to ensure ERCOT System reliability and to ensure that enough Resource capacity, in addition to Ancillary Service capacity, is committed in the right locations to reliably serve the forecasted Load on the ERCOT System including Direct Current Tie (DC Tie) Load that has not been curtailed.

[NPRR1009: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) Transmission security analysis and Reliability Unit Commitment (RUC) are used to ensure ERCOT System reliability and to ensure that enough Resource capacity and qualified Ancillary Service capacity are committed in the right locations to reliably serve the forecasted Load and Ancillary Service needs on the ERCOT System including Direct Current Tie (DC Tie) Load that has not been curtailed.

(2) ERCOT shall conduct at least one Day-Ahead Reliability Unit Commitment (DRUC) and at least one Hourly Reliability Unit Commitment (HRUC) before each hour of the Operating Day. ERCOT, in its sole discretion, may conduct a RUC at any time to evaluate and resolve reliability issues.

(3) The DRUC must be run after the close of the Day-Ahead Market (DAM).

(4) The DRUC uses Three-Part Supply Offers, capped at the maximum of generic or verifiable minimum energy and Startup Costs, submitted before the DAM by Qualified Scheduling Entities (QSEs) that were considered in the DAM but not awarded in the DAM. A QSE may not submit a Three-Part Supply Offer to be considered in the DRUC unless the offer was also submitted for consideration in the DAM.

(5) ERCOT must initiate the HRUC process at least one hour before the Operating Hour to fine-tune the Resource commitments using updated Load forecasts and updated Outage information.

(6) The RUC Study Period for DRUC is the next Operating Day. The RUC Study Period for HRUC is the balance of the current Operating Day plus the next Operating Day if the DRUC for the Operating Day has been solved.

(7) HRUC may decommit Resources only to maintain the reliability of the ERCOT System.

(8) For each RUC Study Period, the RUC considers capacity requirements for each hour of the RUC Study Period with the objective of minimizing costs based on logic described in Section 5.5.2, Reliability Unit Commitment (RUC) Process.

(9) The calculated Resource commitments arising from each RUC process, and a list of Off-Line Available Resources having a start-up time of one hour or less, must be reviewed by ERCOT before issuing Dispatch Instructions to QSEs to commit, extend, or decommit Resources.

(10) The Security Sequence is a set of prerequisite processes for RUC that describes the key system components and inputs that are required to support the RUC process, the RUC process itself, and the ERCOT review of the Resource commitment recommendations made by the RUC process.

(11) The RUC process may not be used to buy Ancillary Service unless the Ancillary Service Offers submitted in the DAM are insufficient to meet the requirements of the Ancillary Service Plan.

[NPRR1009: Delete paragraph (11) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(12) After the use of market processes to the fullest extent practicable without jeopardizing the reliability of the ERCOT System, any ERCOT Dispatch Instructions for additional capacity that order a QSE to commit a specific Generation Resource to be On-Line shall be considered a RUC Dispatch for the purpose of the Settlement of payments and charges related to the committed Generation Resource. An Operating Condition Notice (OCN), Advisory, Watch, or Emergency Notice requesting the available capacity of any currently available Generation Resources but not naming specific Generation Resources is not considered a RUC Dispatch for purposes of Settlement.

(13) ERCOT shall post on the Market Information System (MIS) Certified Area, for each Off-Line Generation Resource that may be selected by an HRUC process, the current time since the Generation Resource last went Off-Line (in hours) and the corresponding start-up times ERCOT is using for each such Off-Line Generation Resource. The time since the Generation Resource last went Off-Line and start-up times shall be updated at least hourly.

(14) Prior to 1330 in the Day-Ahead, ERCOT may issue a Weekly Reliability Unit Commitment (WRUC) Verbal Dispatch Instruction (VDI) to inform a QSE that a Resource is required to be On-Line for all or part of a future Operating Day. Following the receipt of a WRUC:

(a) The QSE may self-commit the Resource for the WRUC-instructed hours by updating the Resource's Current Operating Plan (COP) to reflect the appropriate On-Line Resource Status for the WRUC-instructed hours prior to the DRUC process execution for the associated Operating Day. Resources that have been self-committed by a QSE in accordance with a WRUC:

(i) May have a Three-Part Supply Offer submitted into the DAM, and any of the WRUC-instructed hours in which the Three-Part Supply Offer is awarded in the DAM become DAM-Committed Intervals for the Resource and are settled accordingly; and

(ii) Will not be issued a RUC commitment for the WRUC-instructed hours that were self-committed or DAM-committed.

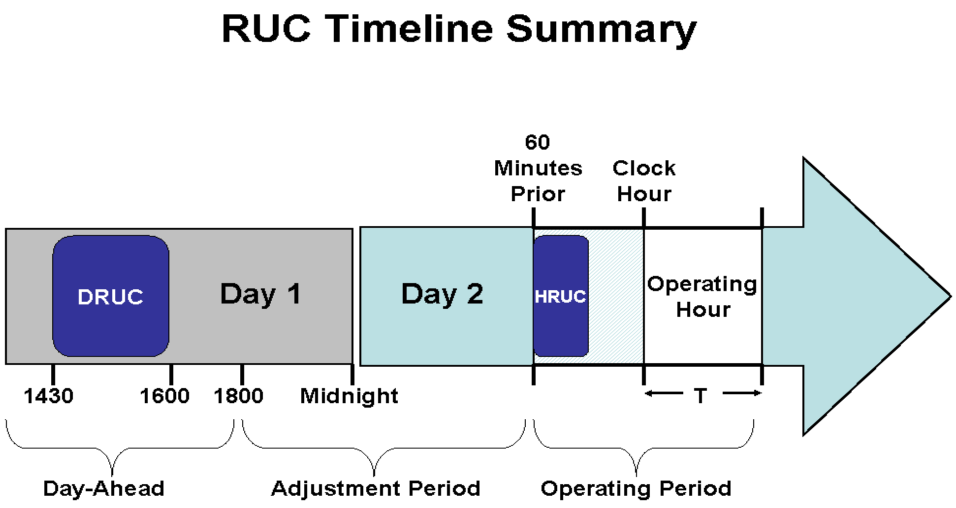
(b) ERCOT will commit the Resource as part of the DRUC process for the relevant Operating Day for all WRUC-instructed hours not DAM-committed or QSE self-committed. For all purposes, including RUC Settlement, the Resource will be considered as committed by the DRUC for these hours.

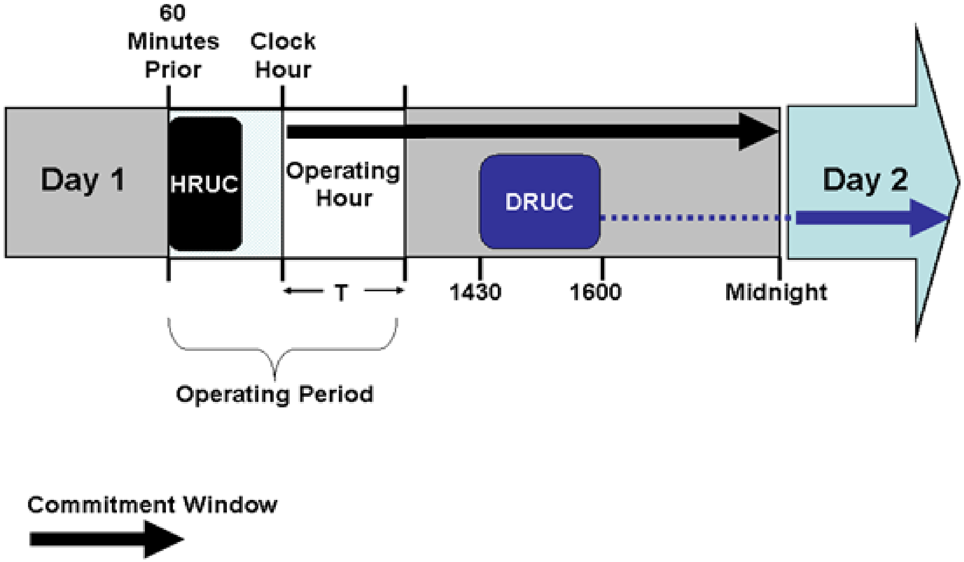
(15) If ERCOT issues an Outage Schedule Adjustment (OSA) pursuant to Section 3.1.4.6, Outage Coordination of Potential Transmission Emergency Conditions, or Section 3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities, QSEs with Resources that received an OSA shall be made whole to their actual costs incurred due to delaying or canceling and rescheduling the Outage as described in Section 5.6.5.1, Make-Whole Payment for Canceled or Delayed Outages for OSAs.

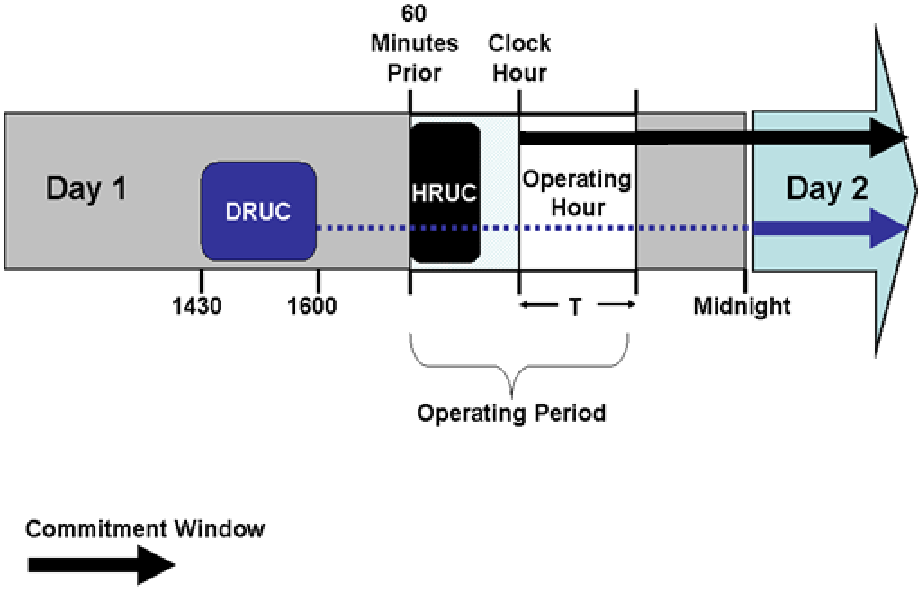
5.2 Reliability Unit Commitment Timeline Summary

5.2.1 RUC Normal Timeline Summary

(1) The following Reliability Unit Commitment (RUC) Timeline Summary describes the normal timeline for RUC activities that occur in the Day-Ahead and Adjustment Periods.







5.2.2 RUC Process Timing Deviations

5.2.2.1 RUC Process Timeline After a Delay of the Day-Ahead Market

(1) If the Day-Ahead Market (DAM) execution is delayed in accordance with Section 4.1.2, Day-Ahead Process and Timing Deviations, ERCOT shall conduct a Day-Ahead

Reliability Unit Commitment (DRUC) after 1430 in the Day-Ahead and no earlier than one hour following the posting of DAM awards information on the ERCOT website as set forth in Section 4.5.3, Communicating DAM Results. In this event, ERCOT will use the Current Operating Plan (COP) and Trades Snapshot taken just prior to the execution of the DRUC to settle RUC charges.

[NPRR1009: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) If the Day-Ahead Market (DAM) execution is delayed in accordance with Section 4.1.2, Day-Ahead Process and Timing Deviations, ERCOT shall conduct a Day-Ahead Reliability Unit Commitment (DRUC) after 1430 in the Day-Ahead and no earlier than one hour following the posting of DAM awards information on the ERCOT website as set forth in Section 4.5.3, Communicating DAM Results. In this event, ERCOT will use the RUC Snapshot taken just prior to the execution of the DRUC to settle RUC charges.

5.2.2.2 RUC Process Timeline After an Aborted Day-Ahead Market

(1) If ERCOT aborts all or part of the Day-Ahead process in accordance with Section 4.1.2, Day-Ahead Process and Timing Deviations, for any reason not due to a Market Suspension, then ERCOT shall use the following Supplemental Ancillary Services Market (SASM) process to purchase Ancillary Services for the next Operating Day and the Hourly Reliability Unit Commitment (HRUC) process described in this Section in lieu of the DRUC process. If ERCOT aborts the Day-Ahead process due to a Market Suspension, it shall act in accordance with Section 25.3, Market Restart Processes.

(2) When the DAM is aborted, ERCOT shall include in the Watch notification required by paragraph (2) of Section 4.1.2 the time when it intends to conduct the SASM described in this Section 5.2.2.2 to procure the amounts of Ancillary Services necessary to meet the Ancillary Service Plan for the Operating Day affected by the aborted DAM. ERCOT shall allow at least one hour between the issuance of the Watch and the beginning of this SASM.

(3) After the issuance of the Watch described in paragraph (2) above and prior to the beginning of this SASM, a Qualified Scheduling Entity (QSE) may cancel unexpired Ancillary Service Offers that were submitted for the aborted DAM.

(4) A QSE may submit Ancillary Service Offers for this SASM after the issuance of the Watch described in paragraph (2) above and prior to the beginning of this SASM.

(5) For this SASM, the QSE must submit the Self-Arranged Ancillary Service Quantity for the next Operating Day in accordance with the timeline described in paragraph (3) of Section 6.4.9.2, Supplemental Ancillary Services Market. This amount may be different from the self-arrangement amounts previously submitted for the aborted DAM.

(6) The amount of each Ancillary Service to be procured by ERCOT in this SASM is the amount of each Ancillary Service specified in the ERCOT Ancillary Service Plan posted prior to the aborted DAM less the total amount of each Ancillary Service in the QSE submittals for self-arranged Ancillary Services for this SASM.

(7) This SASM will settle in accordance with Section 6.7, Real-Time Settlement Calculations for the Ancillary Services.

(8) The SASM process for acquiring Ancillary Services in the event of an aborted Day-Ahead process shall be conducted in accordance with Section 6.4.9.2.2, SASM Clearing Process, but shall use the following activities and timeline as specified in paragraph (3) of Section 6.4.9.2, with time "X" being the time specified by ERCOT for the beginning of the SASM process in the Watch notification described above.

(9) As soon as practicable, but no later than the time specified in paragraph (3) of Section 6.4.9.2, ERCOT shall notify each QSE of its awarded Ancillary Service Offer quantities, specifying Resource, Ancillary Service type, SASM Market Clearing Price for Capacity (MCPC), and the first and last hours of the awarded offer.

(10) As soon as practicable, but no later than the time specified in paragraph (3) of Section 6.4.9.2, ERCOT shall post on the ERCOT website the hourly:

(a) SASM MCPC for each type of Ancillary Service for each hour;

(b) Total Ancillary Service procured in MW by Ancillary Service type for each hour; and

(c) Aggregated Ancillary Service Offer Curve for each Ancillary Service for each hour.

(11) No sooner than 1800 in the Day-Ahead and after the completion of the SASM process described in this Section 5.2.2.2, ERCOT shall execute an HRUC process.

(a) The RUC Study Period for this HRUC process is the balance of the current Operating Day plus the next Operating Day. This HRUC process may be a post-1800 HRUC for the current Operating Day.

(b) The COP and Trades Snapshot taken just prior to the execution of the HRUC process described in this Section 5.2.2.2 will be used to settle RUC charges in the Operating Day affected by the aborted DAM.

(c) This HRUC process described in this Section 5.2.2.2 may commit Resources to supply Ancillary Services if the Ancillary Service Offers submitted in the SASM described in this Section 5.2.2.2 are insufficient to meet the requirements of the Ancillary Services Plan in the Operating Day affected by the aborted DAM.

(d) A QSE may request cancellation of a RUC instruction to supply Ancillary Services if the Resource requested is not capable of providing the Ancillary

Services due to equipment issues that are the result of non-frequency responsive power augmentation or other Resource control issues. If ERCOT accepts the cancellation, ERCOT may require QSEs to submit supporting information describing the Resource control issues.

[NPRR1009: Replace Section 5.2.2.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

5.2.2.2 RUC Process Timeline After an Aborted Day-Ahead Market

(1) If ERCOT aborts all or part of the Day-Ahead process in accordance with Section 4.1.2, Day-Ahead Process and Timing Deviations, for any reason not due to a Market Suspension, then ERCOT shall use the Hourly Reliability Unit Commitment (HRUC) process described in this Section in lieu of the DRUC process. If ERCOT aborts the Day-Ahead process due to a Market Suspension, it shall act in accordance with Section 25.3, Market Restart Processes.

5.3 ERCOT Security Sequence Responsibilities

(1) ERCOT shall start the Day-Ahead Reliability Unit Commitment (DRUC) process at 1430 in the Day-Ahead.

(2) For each DRUC, ERCOT shall use a snapshot of Resource commitments taken at 1430 in the Day-Ahead for Reliability Unit Commitment (RUC) Settlement. For each Hourly Reliability Unit Commitment (HRUC), ERCOT shall use a snapshot of Resource commitments from each Qualified Scheduling Entity's (QSE's) most recently submitted Current Operating Plan (COP) before HRUC execution for RUC Settlement.

(3) For each RUC process, ERCOT shall:

  (a) Execute the Security Sequence described in Section 5.5, Security Sequence, Including RUC, including:

    (i) Validating Three-Part Supply Offers, defined in Section 4.4.9.1, Three-Part Supply Offers;

[NPRR1009 and NPRR1014: Replace item (i) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]

    (i) Validating Three-Part Supply Offers, defined in Section 4.4.9.1, Three-Part Supply Offers, Energy Bid/Offer Curves, defined in Section

4.4.9.7, Energy Bid/Offer Curve, and Ancillary Service Offers, defined in Section 4.4.7.2, Ancillary Service Offers;

(ii) Reviewing the Resource commitment recommendations made by the RUC algorithm; and

(iii) Reviewing the list of Off-Line Available Resources having a start-up time of one hour or less;

(b) Post to the Market Information System (MIS) Secure Area all Resources that were committed or decommitted by the RUC process including verbal RUC commitments and decommitments and Weekly Reliability Unit Commitment (WRUC) instructions;

(c) Post to the ERCOT website all active and binding transmission constraints (contingency and overloaded element pair information where available) used as inputs to the RUC;

(d) Issue Dispatch Instructions to notify each QSE of its Resource commitments or decommitments; and

(e) Post to the MIS Secure Area all Resources that were committed by the RUC process, including verbal RUC commitments, but were subsequently cancelled by the ERCOT Operator.

(4) ERCOT shall provide each QSE with the information necessary to pre-validate their data for DRUC and HRUC, including publishing validation rules for offers, bids, and trades.

5.4 QSE Security Sequence Responsibilities

(1) During the Security Sequence, each Qualified Scheduling Entity (QSE) must:

(a) Submit its Current Operating Plan (COP) and update its COP as required in Section 3.9, Current Operating Plan (COP);

(b) Submit any Three-Part Supply Offers before:

[NPRR1009 and NPRR1014: Replace applicable portions of paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]

(b) Submit any Three-Part Supply Offers, Energy Bid/Offer Curves, and Ancillary Service Offers before:

(i) 1000 in the Day-Ahead for the Day-Ahead Market (DAM) and Day-Ahead Reliability Unit Commitment (DRUC) being run in that Day-Ahead, if the QSE wants the offer to be used in those DAM and DRUC processes; and

(ii) The end of the Adjustment Period for each Hourly Reliability Unit Commitment (HRUC), if the QSE wants the offer to be used in the HRUC process;

(c) Submit any Capacity Trades before 1430 in the Day-Ahead for the DRUC and before the end of the Adjustment Period for each HRUC, if the QSE wants those Capacity Trades included in the calculation of Reliability Unit Commitment (RUC) Settlement;

(d) Submit any Energy Trades and Direct Current Tie (DC Tie) Schedules corresponding to Electronic Tags (e-Tags) before 1430 in the Day-Ahead for the DRUC and by the end of the Adjustment Period for each HRUC; if the QSE wants those Energy Trades and DC Tie Schedules included in the calculation of RUC Settlement;

[NPRR1009 and NPRR1014: Replace applicable portions of paragraph (d) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]

(d) Submit any Energy Trades, Ancillary Service Trades, and Direct Current Tie (DC Tie) Schedules corresponding to Electronic Tags (e-Tags) before 1430 in the Day-Ahead for the DRUC and by the end of the Adjustment Period for each HRUC; if the QSE wants those Energy Trades and DC Tie Schedules included in the calculation of RUC Settlement;

(e) Submit an updated COP before 1430 in the Day-Ahead that shows the specific Resources that will be used to supply the QSE’s Ancillary Service Supply Responsibility; and

[NPRR1009 and NPRR1014: Replace applicable portions of paragraph (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]

(e) Submit an updated COP before 1430 in the Day-Ahead; and

(f) Acknowledge receipt of Resource commitment or decommitment Dispatch Instructions by submitting an updated COP.

[NPRR1009: Insert Section 5.4.1 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

5.4.1 Ancillary Service Positions

(1) A QSE's Ancillary Service Position is the net amount of Ancillary Service capacity to which the QSE has financially committed in the ERCOT market, by hour and service type, from self-arrangement, trades, and awards. The Ancillary Service Position is the difference in MW, by hour and service type, between the amounts specified in items (a) and (b) defined as follows:

(a) The sum of:

(i) The QSE's Self-Arranged Ancillary Service Quantity; plus

(ii) The total (in MW) of Ancillary Service Trades for which the QSE is the seller; plus

(iii) Awards to the QSE of Ancillary Service Offers in the DAM; and

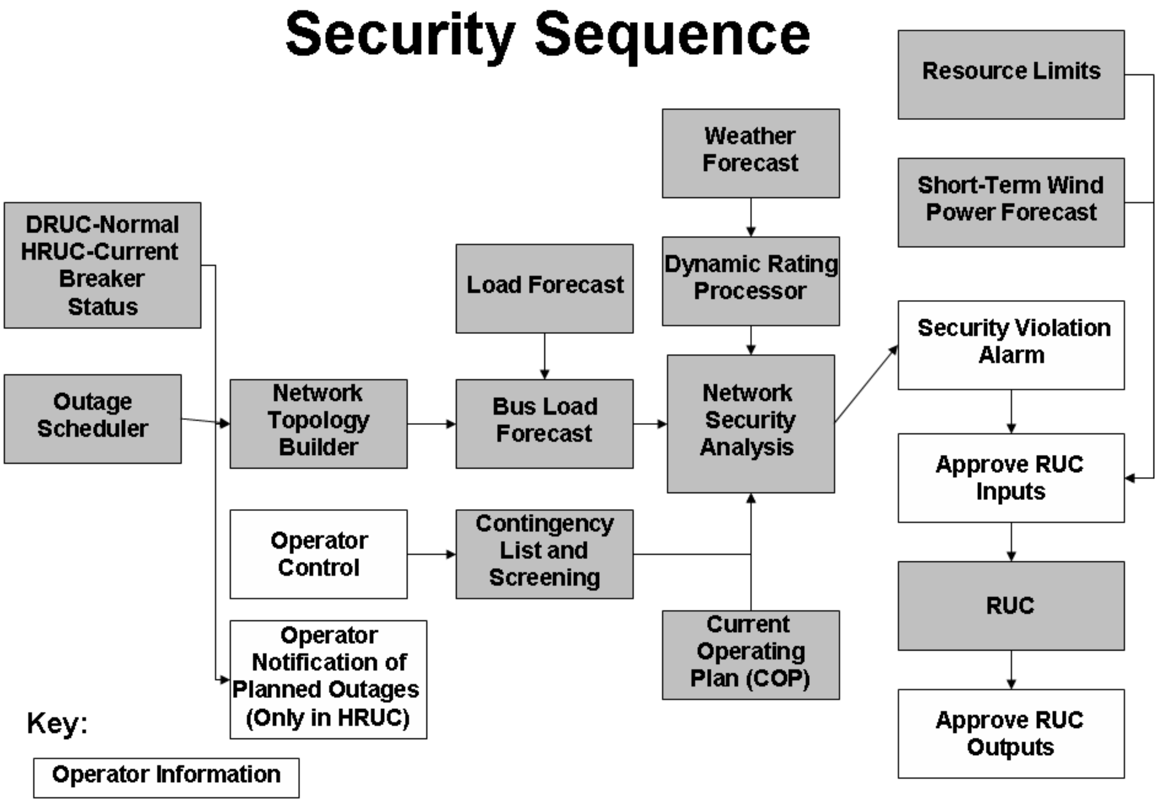
(b) The sum of:

(i) The total Ancillary Service Trades for which the QSE is the buyer.

5.5 Security Sequence, Including RUC

5.5.1 Security Sequence

(1) The figure below highlights the key computational modules and processes that are used in the Security Sequence:



(2) The Security Sequence uses computational modules functionally similar to those used in Real-Time Sequence, however, the inputs into the Security Sequence are based on a snapshot of projected hourly system conditions and constraints rather than Real-Time data.

(3) The Security Sequence uses the status of all transmission breakers and switches (current status for the first hour and normal status for all other hours of Hourly Reliability Unit Commitment (HRUC) and normal status for all hours of Day-Ahead Reliability Unit Commitment (DRUC)), updated for approved Planned Outages for equipment out of service and returned to service for building a representation of the ERCOT Transmission Grid for each hour of the Reliability Unit Commitment (RUC) Study Period. The Network Topology Processor constructs a network model for each hour that must be used by the Bus Load Forecast to estimate the hourly Load for each transmission bus.

(4) The weather forecast obtained by ERCOT must be provided to the Dynamic Rating Processor to create weather-adjusted MVA limits for each hour of the RUC Study Period for all transmission lines and transformers that have Dynamic Ratings.

(5) ERCOT shall analyze base configuration, select n-1 contingencies and select n-2 contingencies under the Operating Guides. The Operating Guides must also specify the criteria by which ERCOT may remove contingencies from the list. ERCOT shall post to the Market Information System (MIS) Secure Area the standard contingency list, including identification of changes from previous versions before being used in the

Security Sequence. ERCOT shall evaluate the need for Resource-specific deployments during Real-Time operations for management of congestion consistent with the Operating Guides.

(6) ERCOT shall also post to the MIS Secure Area any contingencies temporarily removed from the standard contingency list by ERCOT immediately after successful execution of the Security Sequence. ERCOT shall include the reason for removal of any contingency as soon as practicable but not later than one hour after removal.

(7) As part of the Network Security Analysis (NSA), for each hour of the RUC Study Period, ERCOT shall analyze all selected contingencies and perform the following:

(a) Perform full AC analysis of all contingencies;

(b) Monitor element and bus voltage limit violations; and

(c) Monitor transmission line and transformer security violations.

(8) As part of the NSA, if there is an approved Remedial Action Plan (RAP) available, it must be used before considering a Resource commitment.

(9) ERCOT shall review all security violations prior to RUC execution.

(10) All Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs) and RAPs modeled in the Network Operations Model shall be included in the contingency analysis. The computational modules must enable ERCOT to analyze contingencies, including the effects of all RASs and AMPs included in the Network Operations Model.

(11) ERCOT may deselect certain contingencies known to cause errors or that otherwise result in inconclusive study output in the RUC. On continued de-selection of contingencies, ERCOT shall prepare an analysis to determine the cause of the error. ERCOT may use information from the Day-Ahead processes as decision support during the Hour-Ahead processes. ERCOT shall post to the MIS Secure Area any contingencies deselected by ERCOT and must include the reason for removal as soon as practicable, but not later than one hour after deselection.

5.5.2 Reliability Unit Commitment (RUC) Process

(1) The RUC process recommends commitment of Generation Resources, to match ERCOT’s forecasted Load including Direct Current Tie (DC Tie) Schedules, subject to all transmission constraints and Resource performance characteristics. The RUC process takes into account Resources already committed in the Current Operating Plans (COPs), Resources already committed in previous RUCs, Off-Line Available Resources having a start-up time of one hour or less, and Resource capacity already committed to provide Ancillary Service. The formulation of the RUC objective function must employ penalty factors on violations of security constraints. The objective of the RUC process is to minimize costs based on the Resource costs described in paragraphs (5) through (9)

below. For all hours of the RUC Study Period within the RUC process, Quick Start Generation Resources (QSGRs) with a COP Resource Status of OFFQS shall be considered as On-Line with Low Sustained Limit (LSL) at zero MW. QSGRs with a Resource Status of OFFQS shall only be committed by ERCOT through a RUC instruction in instances when a reliability issue would not otherwise be managed through Dispatch Instructions from Security-Constrained Economic Dispatch (SCED).

(2) The RUC process can recommend Resource decommitment. ERCOT may only decommit a Resource to resolve transmission constraints that are otherwise unresolvable. Qualifying Facilities (QFs) may be decommitted only after all other types of Resources have been assessed for decommitment. In addition, the HRUC process provides decision support to ERCOT regarding a Resource decommitment requested by a Qualified Scheduling Entity (QSE).

(3) ERCOT shall review the RUC-recommended Resource commitments and the list of Off-Line Available Resources having a start-up time of one hour or less to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. During the RUC process, ERCOT may also review and commit, through a RUC instruction, Combined Cycle Generation Resources that are currently planned to be On-Line but are capable of transitioning to a configuration with additional capacity. ERCOT may deselect Resources recommended in DRUC and in all HRUC processes if in ERCOT’s sole discretion there is enough time to commit those Resources in the future HRUC processes, taking into account the Resources’ start-up times, to meet ERCOT System reliability. After each RUC run, ERCOT shall post the amount of capacity deselected per hour in the RUC Study Period to the MIS Secure Area. A Generation Resource shown as On-Line and available for SCED dispatch for an hour in its COP prior to a DRUC or HRUC process execution, according to Section 5.3, ERCOT Security Sequence Responsibilities, will be considered self-committed for that hour. For purpose of Settlement, snapshot data will be used as specified in paragraph (2) of Section 5.3. ERCOT shall issue RUC instructions to each QSE specifying its Resources that have been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the MIS Secure Area any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.

(4) A QSE shall notify the ERCOT Operator of any physical limitation that impacts its Resource’s ability to start that is not reflected in the Resource’s COP or the Resource’s startup time, minimum On-Line time, or minimum Off-Line time. The following shall apply:

(a) If a Resource receives a RUC Dispatch Instruction that it cannot meet due to a physical limitation described in paragraph (4) above, the QSE representing the Resource shall notify the ERCOT Operator of the inability to fully comply with the instruction and shall comply with the instruction to the best of the Resource’s ability. If the QSE has provided the ERCOT Operator notice of that limitation at least seven days prior to the Operating Day in which the instruction occurs, the

QSE shall be excused from complying with the portion of the RUC Dispatch Instruction that it could not meet due to the identified limitation.

(b) If a QSE provides notice pursuant to paragraph (a) above of a physical limitation that will delay the RUC-committed Resource's ability to reach its LSL in accordance with a RUC Dispatch Instruction, ERCOT shall extend the RUC Dispatch Instruction so that the Resource's minimum run time is respected. However, if the Resource will not be available in time to address the issue for which it received the RUC instruction, ERCOT may instead cancel the RUC Dispatch Instruction.

(5) A QSE shall be excused from complying with any portion of a RUC Dispatch Instruction that it could not meet due to a physical limitation that was reflected, at the time of the RUC Dispatch Instruction, in the Resource's COP, startup time, minimum On-Line time, or minimum Off-Line time.

(6) To determine the projected energy output level of each Resource and to project potential congestion patterns for each hour of the RUC, ERCOT shall calculate proxy Energy Offer Curves based on the Mitigated Offer Caps (MOCs) for the type of Resource as specified in Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, for use in the RUC. Proxy Energy Offer Curves are calculated by multiplying the MOC by a constant selected by ERCOT from time to time that is no more than 0.10% and applying the cost for all Generation Resource output between High Sustained Limit (HSL) and LSL. The intent of this process is to minimize the effect of the proxy Energy Offer Curves on optimization.

(7) ERCOT shall use the RUC process to evaluate the need to commit Resources for which a QSE has submitted Three-Part Supply Offers and other available Off-Line Resources in addition to Resources that are planned to be On-Line during the RUC Study Period. All of the above commitment information must be as specified in the QSE's COP. For available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (9) below pursuant to paragraph (4) of Section 8.1.2, Current Operating Plan (COP) Performance Requirements, the Startup Offers and Minimum-Energy Offer from a Resource's Three-Part Supply Offer shall not be used in the RUC process.

(8) ERCOT shall create Three-Part Supply Offers for all Resources that did not submit a Three-Part Supply Offer, but are specified as available but Off-Line, excluding Resources with a Resource Status of EMR, in a QSE's COP. For such Resources, excluding available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (9) below pursuant to paragraph (4) of Section 8.1.2, ERCOT shall use in the RUC process 150% of any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as described specified in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, registered with ERCOT. However for Settlement purposes, ERCOT shall use any

approved verifiable Startup Costs and verifiable minimum-energy cost for such Resources, or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and Generic Minimum-Energy Offer Cost.

(9) For all available Off-Line Resources having a cold start time of one hour or less and not removed from special consideration pursuant to paragraph (4) of Section 8.1.2, ERCOT shall scale any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as specified in Section 4.4.9.2.3 for use in the RUC process.

The above parameter is defined as follows:

Parameter	**Unit**	**Current Value***
1HRLESSCOSTSCALING	Percentage	Maximum value of 100%
* The current value for the parameter(s) referenced in this table above will be recommended by the Technical Advisory Committee (TAC) and approved by the ERCOT Board. ERCOT shall update parameter value(s) 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.		

(10) The RUC process must treat all Resource capacity providing Ancillary Service as unavailable for the RUC Study Period, unless that treatment leads to infeasibility (i.e., that capacity is needed to resolve some local transmission problem that cannot be resolved by any other means). If an ERCOT Operator decides that the Ancillary Service capacity allocated to that Resource is infeasible based on ERCOT System conditions, then, ERCOT shall inform each affected QSE of the amount of its Resource capacity that does not qualify to provide Ancillary Service, and the projected hours for which this is the case. In that event, the affected QSE may, under Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints, either:

(a) Substitute capacity from Resources represented by that QSE;

(b) Substitute capacity from other QSEs using Ancillary Service Trades; or

(c) Ask ERCOT to replace the capacity.

(11) Factors included in the RUC process are:

(a) ERCOT System-wide hourly Load forecast allocated appropriately over Load buses;

(b) Transmission constraints – Transfer limits on energy flows through the electricity network;

(i) Thermal constraints – protect transmission facilities against thermal overload;

(ii) Generic constraints – protect the transmission system against transient instability, dynamic instability or voltage collapse;

(c) Planned transmission topology;

(d) Energy sufficiency constraints;

(e) Inputs from the COP, as appropriate;

(f) Inputs from Resource Parameters, including a list of Off-Line Available Resources having a start-up time of one hour or less, as appropriate;

(g) Each Generation Resource's Minimum-Energy Offer and Startup Offer, from its Three-Part Supply Offer;

(h) Any Generation Resource that is Off-Line and available but does not have a Three-Part Supply Offer;

(i) Forced Outage information; and

(j) Inputs from the eight-day look ahead planning tool, which may potentially keep a unit On-Line (or start a unit for the next day) so that a unit minimum duration between starts does not limit the availability of the unit (for security reasons).

(12) The HRUC process and the DRUC process are as follows:

(a) The HRUC process uses current Resource Status for the initial condition for the first hour of the RUC Study Period. All HRUC processes use the projected status of transmission breakers and switches starting with current status and updated for each remaining hour in the study as indicated in the COP for Resources and in the Outage Scheduler for transmission elements.

(b) The DRUC process uses the Day-Ahead forecast of total ERCOT Load including DC Tie Schedules for each hour of the Operating Day. The HRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules for each hour in the RUC Study Period.

(c) The DRUC process uses the Day-Ahead weather forecast for each hour of the Operating Day. The HRUC process uses the weather forecast information for each hour of the balance of the RUC Study Period.

(13) A QSE that has one or more of its Resources RUC-committed to provide Ancillary Services must increase its Ancillary Service Supply Responsibility by the total amount of RUC-committed Ancillary Service quantities. The QSE may only use a RUC-committed Resource to meet its Ancillary Service Supply Responsibility during that Resource's RUC-Committed Interval if the Resource has been committed by the RUC process to provide Ancillary Service, or the Resource is a Combined Cycle Generation Resource that was RUC-committed to transition from one On-Line configuration to a different

configuration with additional capacity. For cases in which the commitment was to provide Ancillary Service, the QSE shall indicate the exact amount and type of Ancillary Service for which it was committed as the Resource's Ancillary Service Resource Responsibility and Ancillary Services Schedule for the RUC-Committed Intervals for both telemetry and COP information provided to ERCOT. Upon deployment of the Ancillary Services, the QSE shall adjust its Ancillary Services Schedule to reflect the amounts requested in the deployment.

(14) A QSE with a Resource that is not a Reliability Must-Run (RMR) Unit or has not received an Outage Schedule Adjustment (OSA) that has been committed in a RUC process or by a RUC Verbal Dispatch Instruction (VDI) may opt out of the RUC Settlement (or "buy back" the commitment) by setting the telemetered Resource Status of the RUC-committed Resource to ONOPTOUT for the first SCED run that the Resource is On-Line and available for SCED dispatch during the first hour of a contiguous block of RUC-Committed Hours. All the configurations of the same Combined Cycle Train shall be treated as the same Resource for the purpose of creating the block of RUC-Committed Hours. A RUC-committed Combined Cycle Generation Resource may opt out of the RUC Settlement by setting the telemetered Resource Status to ONOPTOUT for any On-Line configuration of the same Combined Cycle Train for the first SCED run that the Combined Cycle Train is On-Line and available for SCED Dispatch during the first hour of a contiguous block of RUC-Committed Hours. A Combined Cycle Generation Resource that is RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity may opt out of the RUC Settlement following the same rule for RUC-committed Combined Cycle Generation Resources described above. A QSE that opts out of RUC Settlement forfeits RUC Settlement for the affected Resource for a given block of RUC Buy-Back Hours. A QSE that opts out of RUC Settlement treatment must make the Resource available to SCED for all RUC Buy-Back Hours. All hours in a contiguous block of RUC-Committed Hours that includes the RUC Buy-Back Hour shall be considered RUC Buy-Back Hours. However, if a contiguous block of RUC-Committed Hours spans more than one Operating Day, each contiguous block of RUC-Committed Hours within each Operating Day shall be treated as an independent block for purposes of opting out, and a QSE that wishes to opt out of RUC Settlement for the RUC-Committed Hours in the next Operating Day must set its telemetered Resource Status to ONOPTOUT for the first SCED run the next Operating Day.

(15) If a QSE-committed Resource experiences a Forced Outage or Startup Loading Failure in an hour for which another Resource under the control of the same QSE is committed by a RUC instruction, the QSE may opt out of RUC Settlement for the RUC-committed Resource in accordance with paragraph (14) above, or if the Forced Outage or Startup Loading Failure occurs after the beginning of the first RUC-Committed Interval, the QSE may opt out of RUC Settlement by submitting a dispute pursuant to Section 9.14, Settlement and Billing Dispute Process, requesting a correction of the RUC Settlement treatment for the RUC-committed Resource.

(16) ERCOT shall, as soon as practicable, post to the MIS Secure Area a report identifying those hours that were considered RUC Buy-Back Hours, along with the name of each RUC-committed Resource whose QSE opted out of RUC Settlement.

(17) A Resource that has a Three-Part Supply Offer cleared in the Day-Ahead Market (DAM) and subsequently receives a RUC commitment for the Operating Hour for which it was awarded will be treated as if the telemetered Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Security Constrained Economic Dispatch, and Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder.

[NPRR1009, NPRR1032, and NPRR1092: Replace applicable portions of Section 5.5.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1032 or NPRR1092:]

5.5.2 Reliability Unit Commitment (RUC) Process

(1) The RUC process recommends commitment of Generation Resources, to match ERCOT's forecasted Load including Direct Current Tie (DC Tie) Schedules and RUC Ancillary Service Demand Curves (ASDCs), subject to all transmission constraints and Resource performance characteristics. The RUC process takes into account Resources already committed in the Current Operating Plans (COPs), Resources already committed in previous RUCs, and Off-Line Available Resources having a start-up time of one hour or less. The formulation of the RUC objective function must employ penalty factors on violations of security constraints. The objective of the RUC process is to minimize costs based on the Resource costs described in paragraphs (9) through (13) below.

(2) ERCOT shall create an ASDC for each Ancillary Service for use in RUC. ERCOT shall post the ASDCs to the ERCOT website as soon as practicable after any change to the ASDCs.

(3) For all hours of the RUC Study Period within the RUC process, Quick Start Generation Resources (QSGRs) with a COP Resource Status of OFFQS shall be considered as On-Line with Low Sustained Limit (LSL) at zero MW. QSGRs with a Resource Status of OFFQS shall only be committed by ERCOT through a RUC instruction in instances when a reliability issue would not otherwise be managed through Dispatch Instructions from Security-Constrained Economic Dispatch (SCED).

(4) In addition to On-Line qualified Resources, the RUC engine shall consider a COP Resource status of OFFQS for QSGRs that are qualified for ERCOT Contingency Reserve Service (ECRS), as being eligible to provide ECRS constrained by the Ancillary Service capability in the COP.

(5) In addition to On-Line qualified Resources, the RUC engine shall consider a COP Resource Status of OFFQS for QSGRs that are qualified for Non-Spinning Reserve

(Non-Spin), as being eligible to provide Non-Spin constrained by the Ancillary Service Capability in the COP. The RUC engine shall also consider a COP Resource Status of OFF (Off-Line but available for commitment in the DAM and RUC) for a Resource that is qualified for Non-Spin, as being eligible to provide Non-Spin constrained by the Ancillary Service capability in the COP.

(6) The RUC process can recommend Resource decommitment. ERCOT may only decommit a Resource to resolve transmission constraints that are otherwise unresolvable. Qualifying Facilities (QFs) may be decommitted only after all other types of Resources have been assessed for decommitment. In addition, the HRUC process provides decision support to ERCOT regarding a Resource decommitment requested by a Qualified Scheduling Entity (QSE).

(7) ERCOT shall review the RUC-recommended Resource commitments and the list of Off-Line Available Resources having a start-up time of one hour or less to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. During the RUC process, ERCOT may also review and commit, through a RUC instruction, Combined Cycle Generation Resources that are currently planned to be On-Line but are capable of transitioning to a configuration with additional capacity. ERCOT may deselect Resources recommended in DRUC and in all HRUC processes if in ERCOT’s sole discretion there is enough time to commit those Resources in the future HRUC processes, taking into account the Resources’ start-up times, to meet ERCOT System reliability. After each RUC run, ERCOT shall post the amount of capacity deselected per hour in the RUC Study Period to the MIS Secure Area. A Generation Resource shown as On-Line and available for SCED dispatch for an hour in its COP prior to a DRUC or HRUC process execution, according to Section 5.3, ERCOT Security Sequence Responsibilities, will be considered self-committed for that hour. For purpose of Settlement, snapshot data will be used as specified in paragraph (2) of Section 5.3.

(8) ERCOT shall issue RUC instructions to each QSE specifying its Resources that have been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the MIS Secure Area any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.

(9) ERCOT shall use the RUC process to evaluate the need to commit Resources for which a QSE has submitted Three-Part Supply Offers and other available Off-Line Resources in addition to Resources that are planned to be On-Line during the RUC Study Period. All of the above commitment information must be as specified in the QSE’s COP. For available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (15) below pursuant to paragraph (4) of Section 8.1.2, Current Operating Plan (COP) Performance Requirements, the Startup Offers and Minimum-Energy Offer from a Resource’s Three-Part Supply Offer shall not be used in the RUC process.

(10) ERCOT shall create Three-Part Supply Offers for all Resources that did not submit a Three-Part Supply Offer, but are specified as available but Off-Line, excluding Resources with a Resource Status of EMR, in a QSE's COP. For such Resources, excluding available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (13) below pursuant to paragraph (4) of Section 8.1.2, ERCOT shall use in the RUC process 150% of any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as described specified in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, registered with ERCOT. However for Settlement purposes, ERCOT shall use any approved verifiable Startup Costs and verifiable minimum-energy cost for such Resources, or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and Generic Minimum-Energy Offer Cost.

(11) A QSE shall notify the ERCOT Operator of any physical limitation that impacts its Resource's ability to start that is not reflected in the Resource's COP or the Resource's startup time, minimum On-Line time, or minimum Off-Line time. The following shall apply:

(a) If a Resource receives a RUC Dispatch Instruction that it cannot meet due to a physical limitation described in paragraph (4) above, the QSE representing the Resource shall notify the ERCOT Operator of the inability to fully comply with the instruction and shall comply with the instruction to the best of the Resource's ability. If the QSE has provided the ERCOT Operator notice of that limitation at least seven days prior to the Operating Day in which the instruction occurs, the QSE shall be excused from complying with the portion of the RUC Dispatch Instruction that it could not meet due to the identified limitation.

(b) If a QSE provides notice pursuant to paragraph (a) above of a physical limitation that will delay the RUC-committed Resource's ability to reach its LSL in accordance with a RUC Dispatch Instruction, ERCOT shall extend the RUC Dispatch Instruction so that the Resource's minimum run time is respected. However, if the Resource will not be available in time to address the issue for which it received the RUC instruction, ERCOT may instead cancel the RUC Dispatch Instruction.

(12) A QSE shall be excused from complying with any portion of a RUC Dispatch Instruction that it could not meet due to a physical limitation that was reflected, at the time of the RUC Dispatch Instruction, in the Resource's COP, startup time, minimum On-Line time, or minimum Off-Line time.

(13) To determine the projected energy output level of each Resource and to project potential congestion patterns for each hour of the RUC, ERCOT shall calculate proxy Energy Offer Curves based on the Mitigated Offer Caps (MOCs) for the type of Resource as specified in Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, for use in the RUC. Proxy Energy Offer Curves are calculated by multiplying

the MOC by a constant selected by ERCOT from time to time that is no more than 0.10% and applying the cost for all Generation Resource output between High Sustained Limit (HSL) and LSL. The intent of this process is to minimize the effect of the proxy Energy Offer Curves on optimization.

(14) ERCOT shall calculate proxy Ancillary Service Offer Curves for use in RUC based on validated Ancillary Service Offers as specified in Section 4.4.7.2, Ancillary Service Offers. For all Resources that do not have a valid Ancillary Service Offer but are qualified to provide an Ancillary Service, ERCOT shall create an Ancillary Service Offer Curve for use in RUC as described in Section 6.5.7.3, Security Constrained Economic Dispatch. Proxy Ancillary Service Offer Curves for use in RUC are calculated by multiplying the Ancillary Service Offer by a constant selected by ERCOT from time to time that is no more than 0.1%, and are extended between the HSL and LSL. Notwithstanding the presence or absence of a proxy Ancillary Service Offer, Ancillary Service provision in RUC shall be limited by the Resource's Ancillary Service capabilities as reflected in the COP.

(15) For all available Off-Line Resources having a cold start time of one hour or less and not removed from special consideration pursuant to paragraph (4) of Section 8.1.2, ERCOT shall scale any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as specified in Section 4.4.9.2.3 for use in the RUC process.

The above parameter is defined as follows:

Parameter	**Unit**	**Current Value***
1HRLESSCOSTSCALING	Percentage	Maximum value of 100%
* The current value for the parameter(s) referenced in this table above will be recommended by the Technical Advisory Committee (TAC) and approved by the ERCOT Board. ERCOT shall update parameter value(s) 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.		

(16) Factors included in the RUC process are:

(a) ERCOT System-wide hourly Load forecast allocated appropriately over Load buses;

(b) ERCOT's Ancillary Service Plans in the form of ASDCs;

(c) Transmission constraints – Transfer limits on energy flows through the electricity network;

(i) Thermal constraints – protect transmission facilities against thermal overload;

(ii) Generic constraints – protect the transmission system against transient instability, dynamic instability or voltage collapse;

(d) Planned transmission topology;

(e) Energy sufficiency constraints;

(f) Inputs from the COP, as appropriate;

(g) Inputs from Resource Parameters, including a list of Off-Line Available Resources having a start-up time of one hour or less, as appropriate;

(h) Each Generation Resource's Minimum-Energy Offer and Startup Offer, from its Three-Part Supply Offer;

(i) Any Generation Resource that is Off-Line and available but does not have a Three-Part Supply Offer;

(j) Forced Outage information; and

(k) Inputs from the eight-day look ahead planning tool, which may potentially keep a unit On-Line (or start a unit for the next day) so that a unit minimum duration between starts does not limit the availability of the unit (for security reasons).

(17) The HRUC process and the DRUC process are as follows:

(a) The HRUC process uses current Resource Status for the initial condition for the first hour of the RUC Study Period. All HRUC processes use the projected status of transmission breakers and switches starting with current status and updated for each remaining hour in the study as indicated in the COP for Resources and in the Outage Scheduler for transmission elements.

(b) The DRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules up to the physical rating of the DC Tie for each hour of the Operating Day. The HRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules up to the physical rating of the DC Tie for each hour in the RUC Study Period.

(c) The DRUC process uses the Day-Ahead weather forecast for each hour of the Operating Day. The HRUC process uses the weather forecast information for each hour of the balance of the RUC Study Period.

(18) A QSE with a Resource that is not a Reliability Must-Run (RMR) Unit or has not received an Outage Schedule Adjustment (OSA) that has been committed in a DRUC or HRUC process may opt out of the RUC Settlement (or "buy back" the commitment) by setting the COP status of the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. All the configurations of the same Combined Cycle Train shall be treated as the same Resource

for the purpose of creating the block of RUC-Committed Hours. A RUC-committed Combined Cycle Generation Resource may opt out of the RUC Settlement by setting the COP status of any Combined Cycle Generation Resource within the same Combined Cycle Train as the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. A Combined Cycle Generation Resource that is RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity may opt out of the RUC Settlement following the same rule for RUC-committed Combined Cycle Generation Resources described above. A QSE that opts out of RUC Settlement forfeits RUC Settlement for the affected Resource for a given block of RUC Buy-Back Hours. A QSE that opts out of RUC Settlement treatment must make the Resource available to SCED for all RUC Buy-Back Hours. All hours in a contiguous block of RUC-Committed Hours that includes the RUC Buy-Back Hour shall be considered RUC Buy-Back Hours. If a contiguous block of RUC-Committed Hours spans more than one Operating Day and a QSE wishes to opt out of RUC Settlement for the RUC-Committed Hours in the second or subsequent Operating Day, the QSE must set its COP status to ONOPTOUT for the first hour of that the first Operating Day in the Opt Out Snapshot of the first Operating Day.

(19) ERCOT shall, as soon as practicable, post to the MIS Secure Area a report identifying those hours that were considered RUC Buy-Back Hours, along with the name of each RUC-committed Resource whose QSE opted out of RUC Settlement.

(20) A Resource that has a Three-Part Supply Offer cleared in the Day-Ahead Market (DAM) and subsequently receives a RUC commitment for the Operating Hour for which it was awarded will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3 and Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders.

(21) A Resource that has self-committed for an Operating Hour after the RUC Snapshot was taken but before the RUC commitment has been communicated through an XML message for that RUC process and that Operating Hour is included in a block of RUC-committed hours for that RUC process will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Section 6.5.7.3.1, Operating Reserve Demand Curve (ORDC) calculations, and RUC Settlement for the entire block of RUC-committed hours. A QSE that has a Resource that meets these conditions must make the Resource available to SCED for the entire block of RUC-committed hours. ERCOT will send the QSE a notification stating the Operating Day and block of hours for which this occurred.

5.5.3 Communication of RUC Commitments and Decommitments

(1) The output of the RUC process is the cleared Resource commitments and decommitments, and a list of the Off-Line Available Resources having a start-up time of one hour or less.

(2) ERCOT shall notify each QSE in the Day-Ahead of the DRUC Resource commitments and advisory decommitments that have been cleared by the RUC for the Resources that QSE represents. ERCOT shall notify each QSE of the HRUC Resource commitments and decommitments that have been cleared by the RUC for the Resources that QSE represents. Resource commitments must include the start interval and duration for which the Resource is required to be at least at LSL. Resource decommitments must include the interval in which the Resource is required to be Off-Line, duration, and reason for the decommitment. ERCOT shall notify each QSE representing an RMR Unit if that unit has been cleared by the DRUC or HRUC process at the same time that the DRUC and HRUC participants are notified of the results of each such process.

(3) If ERCOT communicates HRUC commitments and decommitments verbally to a QSE, then the same Resource attributes communicated programmatically must be communicated when ERCOT gives a verbal Resource commitment or decommitment.

(4) The QSE shall acknowledge the notice or commitment or decommitment by changing the Resource Status of the affected Resources in the COP for RUC-Committed Intervals.

5.6 RUC Cost Eligibility

5.6.1 Verifiable Costs

(1) The Qualified Scheduling Entity (QSE) is responsible for submitting verifiable costs unless both the QSE and Resource Entity agree that the Resource Entity will have this responsibility, in which case both the QSE and Resource Entity shall submit an affidavit to ERCOT stating this arrangement. Notwithstanding the foregoing, QSEs that submit Power Purchase or Tolling Agreements (PPAs) do not have the option of allowing Resource Entities to file verifiable costs.

(2) Make-Whole Payments for a Resource are based on the Startup Offers and Minimum-Energy Offers for the Resource, limited by caps. Until ERCOT approves verifiable unit-specific costs for that Resource, the caps are the Resource Category Startup Generic Cap and the Resource Category Minimum-Energy Generic Cap. When ERCOT approves verifiable unit-specific costs for that Resource the caps are those verifiable unit-specific costs. A QSE or Resource Entity may file verifiable unit-specific costs for a Resource at any time, but it must file those costs no later than 30 days after five Reliability Unit Commitment (RUC) events for that Resource in a calendar year. A RUC event begins when a Resource receives a RUC instruction to come or stay On-Line and ends the later of when the Resource shuts down or the end of the Operating Day. The most recent ERCOT-approved verifiable costs must be used going forward.

(3) These unit-specific verifiable costs may include and are limited to the following average incremental costs:

(a) Allocation of maintenance requirements based on number of starts between maintenance events using, at the option of the QSE or Resource Entity, either:

(i) Manufacturer-recommended maintenance schedule;

(ii) Historical data for the unit and actual maintenance practices; or

(iii) Another method approved in advance by ERCOT in writing;

(b) Startup fuel calculations based on recorded actual measured flows when the data is available or based on averages of historical flows for similar starts (for example, hot, cold, intermediate) when actual data is not available. Startup fuel will include filing separately the startup fuel required to reach breaker close and fuel after breaker close to Low Sustained Limit (LSL). Any fuel required to shutdown a Resource will be submitted as the fuel from breaker open to shutdown;

(c) Operation costs;

(d) Chemical costs;

(e) Water costs; and

(f) Emission credits.

(4) Standard Operations and Maintenance (O&M) costs pursuant to paragraph (6) below may be used in lieu of the incremental O&M costs set forth in items (3)(a), (c), (d) and (e) above.

(5) These unit-specific verifiable costs may not include:

(a) Fixed costs, which are any cost that is incurred regardless of whether the unit is deployed or not; and

(b) Costs for which the QSE or Resource Entity cannot provide sufficient documentation for ERCOT to verify the costs.

(6) At their election, QSEs or Resource Entities may receive standard O&M costs for both startup and minimum energy. This election may be made by submitting an election form to ERCOT. If a QSE or Resource has received final approval for actual verifiable O&M costs under the verifiable cost process, it may not elect to receive standard O&M costs.

(a) Until December 31, 2011, standard O&M costs are defined as follows:

Resource Category Start Year = 2009	**Cold Startup ($/start)**	**Intermediate Startup ($/start)**	**Hot Startup ($/start)**	**Variable O&M ($/MWh)**
Aeroderivative simple cycle commissioned after 1996	1,000.00	1,000.00	1,000.00	3.94

Reciprocating Engine	$58/MW * the average of the Seasonal net max sustainable ratings	$58/MW * the average of the Seasonal net max sustainable ratings	$58/MW * the average of the Seasonal net max sustainable ratings	5.09
Simple cycle ≤ 90 MW	2,300.00	2,300.00	2,300.00	3.94
Simple cycle ≥ 90 MW	5,000.00	5,000.00	5,000.00	3.94
Combined cycle: for each Combined-Cycle Configuration, the Startup Cost for that configuration is the sum of the Startup Costs for each unit within that configuration as follows:				3.19
Combustion turbine < 90 MW	2,300.00	2,300.00	2,300.00	
Combustion turbine ≥ 90 MW	5,000.00	5,000.00	5,000.00	
Steam turbine	3,000.00	2,250.00	1,250.00	
Gas-steam non-reheat boiler	2,310.00	1,732.50	866.25	7.08
Gas-steam reheat boiler	3,000.00	2,250.00	1,125.00	7.08
Gas-steam supercritical boiler	4,800.00	3,600.00	1,800.00	7.08
Nuclear, coal, lignite and hydro	7,200.00	5,400.00	2,700.00	5.02
Renewable	Not Applicable	Not Applicable	Not Applicable	5.50

(b) For the period beginning January 1, 2012 and ending December 31, 2012, standard O&M costs shall be reduced by 10% from the levels specified in the table in paragraph (a) above as follows:

Resource Category **Start Year = 2009**	**Cold Startup ($/start)**	**Intermediate Startup ($/start)**	**Hot Startup ($/start)**	**Variable O&M ($/MWh)**
Aeroderivative simple cycle commissioned after 1996	900.00	900.00	900.00	3.55
Reciprocating Engine	$52.20/MW * the average of the Seasonal net max sustainable ratings	$52.20/MW * the average of the Seasonal net max sustainable ratings	$52.20/MW * the average of the Seasonal net max sustainable ratings	4.58
Simple cycle ≤ 90 MW	2,070.00	2,070.00	2,070.00	3.55
Simple cycle ≥ 90 MW	4,500.00	4,500.00	4,500.00	3.55
Combined cycle: for each Combined-Cycle Configuration, the Startup Cost for that configuration is the sum of the Startup Costs for each unit				2.87

Resource Category **Start Year = 2009**	**Cold Startup ($/start)**	**Intermediate Startup ($/start)**	**Hot Startup ($/start)**	**Variable O&M ($/MWh)**
within that configuration as follows:				
Combustion turbine < 90 MW	2,070.00	2,070.00	2,070.00	
Combustion turbine ≥ 90 MW	4,500.00	4,500.00	4,500.00	
Steam turbine	2,700.00	2,025.00	1,125.00	
Gas-steam non-reheat boiler	2,079.00	1,559.25	779.63	6.37
Gas-steam reheat boiler	2,700.00	2,025.00	1,012.50	6.37
Gas-steam supercritical boiler	4,320.00	3,240.00	1,620.00	6.37
Nuclear, coal, lignite and hydro	6,480.00	4,860.00	2,430.00	4.52
Renewable	Not Applicable	Not Applicable	Not Applicable	4.95

(c) Beginning January 1, 2013 and going forward, standard O&M costs shall be reduced by 20% from the levels specified in the table in paragraph (a) above as follows:

Resource Category **Start Year = 2009**	**Cold Startup ($/start)**	**Intermediate Startup ($/start)**	**Hot Startup ($/start)**	**Variable O&M ($/MWh)**
Aeroderivative simple cycle commissioned after 1996	800.00	800.00	800.00	3.15
Reciprocating Engine	$46.40/MW * the average of the Seasonal net max sustainable ratings	$46.40 /MW * the average of the Seasonal net max sustainable ratings	$46.40 /MW * the average of the Seasonal net max sustainable ratings	4.07
Simple cycle ≤ 90 MW	1,840.00	1,840.00	1,840.00	3.15
Simple cycle ≥ 90 MW	4,000.00	4,000.00	4,000.00	3.15
Combined cycle: for each Combined-Cycle Configuration, the Startup Cost for that configuration is the sum of the Startup Costs for each unit within that configuration as follows:				2.55
Combustion turbine < 90 MW	1,840.00	1,840.00	1,840.00	
Combustion turbine ≥ 90 MW	4,000.00	4,000.00	4,000.00	
Steam turbine	2,400.00	1,800.00	1,000.00	

Resource Category **Start Year = 2009**	**Cold Startup ($/start)**	**Intermediate Startup ($/start)**	**Hot Startup ($/start)**	**Variable O&M ($/MWh)**
Gas-steam non-reheat boiler	1,848.00	1,386.00	693.00	5.66
Gas-steam reheat boiler	2,400.00	1,800.00	900.00	5.66
Gas-steam supercritical boiler	3,840.00	2,880.00	1,440.00	5.66
Nuclear, coal, lignite and hydro	5,760.00	4,320.00	2,160.00	4.02
Renewable	Not Applicable	Not Applicable	Not Applicable	4.40

(d) If the QSE or Resource Entity chooses to utilize the standard O&M costs for O&M, standard O&M costs will be used by ERCOT going forward until either:

(i) Verifiable variable O&M costs are filed; or

(ii) ERCOT notifies the QSE or Resource Entity to update its verifiable costs as set forth in either paragraph (9) or (10) below. If a Resource is receiving standard O&M costs, it may reelect standard O&M costs when resubmitting verifiable costs.

(7) When submitting verifiable costs for combined cycle Resources, the QSE or Resource Entity must elect standard O&M costs for all Combined-Cycle Configurations or verifiable costs for all Combined-Cycle Configurations within the combined cycle train.

(8) QSEs submitting PPAs as Resource-specific verifiable costs documentation are subject to the guidelines detailed below and in the Verifiable Cost Manual.

(a) Only QSEs offering Three-Part Supply Offers for a specific Resource may submit a PPA as verifiable costs documentation.

(b) A QSE submitting a PPA as verifiable costs documentation must represent 100% of the Resource’s capacity.

(c) Only PPAs:

(i) Signed prior to July 16, 2008; and

(ii) Not between Affiliates, subsidiaries or partners will be accepted as verifiable cost documentation.

(d) Verifiable costs for PPAs shall be capped at the level of the highest comparable Resource (referred to as the reference Resource) specific verifiable costs approved by ERCOT without a PPA. The ERCOT approved verifiable costs for a PPA shall be equal to the lesser of:

(i) The cap as described in paragraph (d) above; and

(ii) The costs from the PPA.

(e) ERCOT shall use the Resource actual fuel costs submitted by the QSE for startup and operation at minimum-energy level (LSL), and shall use the Resource Category Startup Offer Generic Costs as the cap for the O&M portion of the Startup Costs until ERCOT receives and approves comparable Resource specific verifiable costs.

(f) PPAs will no longer be accepted as verifiable cost documentation after the primary term of the contract expires.

(g) ERCOT shall produce a report each April that provides the percentage of RUC Make-Whole Payments for Resources with PPAs during the 12 months of the previous calendar year. If there are no Make-Whole Payments for Resources with PPAs, ERCOT shall not produce the annual report. The report shall be based on the final Settlements and include the total number of Resources that used a PPA for their most recent verifiable cost submission that was approved by ERCOT. ERCOT shall present the results of this study to the appropriate Technical Advisory Committee (TAC) subcommittee.

(h) Notwithstanding anything to the contrary in this Section 5.6.1, QSEs representing PPAs may, at any time, submit data from a Resource as verifiable costs documentation and such documentation will be accepted for consideration by ERCOT. A QSE submitting verifiable costs documentation pursuant to this paragraph shall not be required to submit a PPA to ERCOT for consideration for verifiable cost recovery.

(9) ERCOT shall notify a QSE to update verifiable cost data of a Resource when the Resource has received more than 50 RUC instructions meeting the criteria in Section 5.6.2, RUC Startup Cost Eligibility, in a year, but ERCOT may not request an update more frequently than annually.

(10) ERCOT shall notify a QSE to update verifiable cost data of a Resource if at least five years have passed since ERCOT previously approved verifiable cost data for that Resource.

(11) Within 30 days after receiving an update Notice from ERCOT under either paragraph (9) or (10) above, a QSE or Resource Entity must submit verifiable cost data for the Resource. Despite the provisions in paragraph (2) above, if the QSE or Resource Entity does not submit verifiable cost data within 30 days after receiving an update Notice, then ERCOT shall determine payment using the Resource Category Startup Offer Generic Cap, Resource Category Minimum-Energy Offer Generic Cap, and a zeroed value for variable O&M cost as described in Section 4.4.9.4.1, Mitigated Offer Cap, in accordance with the schedule established in this section until updated verifiable costs are approved. If the 30-day deadline has been reached before the start of the tenth day before the end of the month, the Resource’s verifiable costs will revert back to generic costs beginning on the first day of the following month. If the 30-day deadline falls within the last ten days of the month, the Resource’s verifiable costs will revert back to generic costs on the first day of the second month following the deadline month.

(12) Notwithstanding the foregoing, QSEs and Resource Entities shall not submit verifiable costs for Energy Storage Resources (ESRs).

5.6.1.1 Verifiable Startup Costs

(1) The unit-specific verifiable costs for starting a Resource for each cold, intermediate, and hot start condition, as determined using the data submitted under Section 5.6.1, Verifiable Costs, and the Resource Parameters for the Resource are:

(a) Actual fuel consumption rate per start (MMBtu/start) multiplied by a resource fuel price plus consideration of a fuel adder that compensates for the transportation and purchasing of spot fuel as described in the Verifiable Cost Manual; and

(b) Unit-specific verifiable or standard O&M expenses.

5.6.1.2 Verifiable Minimum-Energy Costs

(1) The unit-specific verifiable minimum-energy costs for a Resource are:

(a) Actual fuel cost to operate the unit at its LSL including a fuel adder that compensates for the transportation and purchasing of spot fuel as described in the Verifiable Cost Manual; plus

(b) Verifiable or standard variable O&M expenses.

(2) The QSE must submit the Resource's cost information by Season if the Resource's costs vary by Season. For gas-fired units, the actual fuel costs must be calculated using the actual Seasonal heat rate (which must be supplied to ERCOT with Seasonal heat-rate test data) multiplied by the fuel price plus consideration of a fuel adder that compensates for the transportation and purchasing of spot fuel as described in the Verifiable Cost Manual. For coal- and lignite-fired units, the actual fuel costs must be calculated using the actual Seasonal heat rate multiplied by a deemed fuel price of $1.50 per MMBtu. For fuel oil-fired operations, the number of gallons burned must be multiplied by the FOP.

5.6.2 RUC Startup Cost Eligibility

(1) For purposes of this Section 5.6.2, all contiguous RUC-Committed Hours are considered as one RUC instruction. For each Resource, only one Startup Cost is eligible per block of contiguous RUC-Committed Hours.

(2) For a Resource's Startup Costs in the Operating Day, per RUC instruction, to be included in the calculation of the RUC guarantee for that Operating Day, all the criteria below must be met:

(a) According to the Current Operating Plan (COP) and Trades Snapshot for the RUC process that committed the Resource, the Resource must not be QSE-committed in the Settlement Interval immediately before the designated start hour or after the last hour of the RUC instruction;

[NPRR1009: Replace paragraph (a) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(a) According to the RUC Snapshot for the RUC process that committed the Resource, the Resource must not be QSE-committed in the Settlement Interval immediately before the designated start hour or after the last hour of the RUC instruction;

(b) A later RUC instruction or QSE commitment must not connect the designated start hour or last hour of the RUC instruction to a block of QSE-committed Intervals that was QSE-committed before the RUC instruction was given, according to the COP and Trades Snapshot for the RUC process that committed the Resource;

[NPRR1009: Replace paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(b) A later RUC instruction or QSE commitment must not connect the designated start hour or last hour of the RUC instruction to a block of QSE-committed Intervals that was QSE-committed before the RUC instruction was given, according to the RUC Snapshot for the RUC process that committed the Resource;

(c) The generation breakers must have been open, as indicated by a telemetered Resource Status of Off-Line, for at least five minutes during the six hours preceding the first RUC-Committed Hour; and

(d) The generation breakers must have been closed, as indicated by a telemetered Resource Status of On-Line, for at least one minute during the RUC commitment period or after the determined five-minute open breaker, as indicated by a telemetered Resource Status of Off-Line, in the six hours preceding the first RUC-Committed Hour.

(3) Notwithstanding paragraphs (2)(c) and (2)(d) above, the QSE of a RUC-committed Resource may submit a Settlement dispute for a Resource’s Startup Costs in the Operating Day, per RUC instruction, to be included in the calculation of the RUC guarantee for that Operating Day if the startup time for the RUC-committed Resource is greater than six hours. The dispute is subject to verification and approval by ERCOT based on the criteria below:

(a) The generation breakers must have been open, as indicated by a telemetered Resource Status of Off-Line, for at least five minutes between the time the QSE is notified of the RUC instruction and the first RUC-Committed Hour;

(b) The generation breakers must have been closed, as indicated by a telemetered Resource Status of On-Line, for at least one minute during the RUC commitment period or after the five-minute open breaker determined in item (a) above;

(c) The breaker open-close sequence from items (a) and (b) above does not make the Resource eligible for Startup Cost compensation in the Day-Ahead Market (DAM) or for any other contiguous block of RUC-Committed Hours; and

(d) The startup time used to process the dispute will be the startup time considered by the ERCOT Operator at the time the RUC instruction was issued.

(4) For purposes of this Section 5.6.2, the telemetered Resource Status of OFFQS shall be considered as Off-Line.

(5) A Resource that has a Three-Part Supply Offer cleared in the DAM and subsequently receives a RUC commitment for the Operating Hour for which it was awarded will be settled in accordance with Section 4.6.2.3, Day-Ahead Make-Whole Settlements.

5.6.3 Forced Outage of a RUC-Committed Resource

(1) The calculation of a Make-Whole Payment for a RUC-committed Resource that is eligible to receive startup costs under Section 5.6.2, RUC Startup Cost Eligibility, and that experiences a Forced Outage after unit synchronization is governed by Section 5.6.2.

(2) If a RUC-committed Resource, which Resource is eligible to include startup costs in its RUC guarantee under Section 5.6.2 without considering the criteria in item (2)(d) of Section 5.6.2, experiences startup failure that creates a Forced Outage before breaker close, ERCOT shall include the Resource’s submitted and approved verifiable actual costs in the Resource’s RUC guarantee, limited to the lesser of:

(a) Costs that qualify as normal startup expenses, including fuel and operation and maintenance expenses, incurred before the event that caused the Forced Outage; or

(b) Resource’s Startup Offer in the RUC.

(3) The process for determining the verifiable actual costs for a startup attempt under item (2) above is described in the Verifiable Cost Manual.

(4) The verifiable actual costs for a startup attempt under item (2) above shall only be included in the Resource’s RUC guarantee upon QSE notification of the startup attempt under item (2) and approval of the verifiable actual costs under item (3) above.

5.6.4 Cancellation of a RUC Commitment

(1) The calculation of payment for a RUC-committed Resource that is issued a RUC Cancellation instruction for the RUC commitment from ERCOT prior to breaker close shall be paid through the RUC Decommitment Payment as described in Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource.

(2) A RUC-committed Resource that receives a RUC Cancellation instruction prior to breaker close may submit through the dispute process all incremental expenses associated with the RUC Cancellation of the RUC-committed Resource. These costs include all costs that qualify as normal Startup Costs, O&M expenses and associated fuel expenses incurred for any attempted start.

(3) The process for determining the verifiable actual costs for a RUC cancellation is described in the Verifiable Cost Manual.

5.6.5 Settlement for Canceled or Delayed Outages for Outage Schedule Adjustments (OSAs)

5.6.5.1 Make-Whole Payment for Canceled or Delayed Outages for OSAs

(1) If ERCOT issues an Outage Schedule Adjustment (OSA) pursuant to Section 3.1.4.6, Outage Coordination of Potential Transmission Emergency Conditions, or Section 3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities, ERCOT shall pay the QSE representing the Resource a Make-Whole Payment as calculated in Section 5.6.5.2, RUC Make-Whole Payment and RUC Clawback Charge for Resources Receiving OSAs, if the QSE has:

(a) Submitted a Settlement and billing dispute consistent with the dispute process described in Section 9.14, Settlement and Billing Dispute Process; and

(b) Submitted the following within 60 days of the issuance of a Real-Time Market (RTM) Initial Statement for an Operating Day on which one or more OSAs was in effect for the Resource:

(i) An attestation signed by an officer or executive with authority to bind the QSE stating that the information contained in the submission is accurate;

(ii) The dollar amount and calculation of the net financial loss, if applicable, by Settlement Interval for:

(A) Actual and indirect costs incurred due to delaying or canceling and rescheduling the Outage. Such costs include, but are not limited to:

(1) Additional staff or contractor time;

(2) Costs associated with re-planning the Outage;

(3) Costs of equipment rental (including but not limited to cranes, manlifts, welding machines, etc.);

(4) Costs of facility rentals and other incidental incremental costs incurred by the Resource, its QSE, or its fuel supplier (e.g. mine-related expenses) created by the cancellation or delay of the Outage; and

(5) Indirect costs necessary for moving any additional Outages due to the OSA.

(B) Costs covered by paragraph (A) above do not include:

(1) The cost of materials due to be installed during the Outage. Such equipment will presumably be installed at a later date in a rescheduled or delayed Outage; and

(2) All loss amounts associated with the Outage Resource as a result of any financial transaction, including selling or repurchasing a hedge (whether the hedge is for energy, Ancillary Services, or fuel); and

(iii) Sufficient documentation to support the QSE’s calculation of all submitted costs.

5.6.5.2 RUC Make-Whole Payment and RUC Clawback Charge for Resources Receiving OSAs

(1) To compensate QSEs representing Resources that submitted a timely Settlement and billing dispute, ERCOT shall calculate a RUC Guarantee for an Operating Day for the OSA Period to be used in the RUC Settlements process and allocated to each instructed Operating Hour as follows:

(a) For a Resource with RUC instructions issued for hours during the OSA Period, the RUC Guarantee calculated for the RUC-Committed Hours shall include the following:

(i) Eligible Startup costs per Section 5.6.2, RUC Startup Cost Eligibility;

(ii) Minimum-energy costs;

(iii) 10% of both Startup costs and minimum-energy costs; and

(iv) Approved net financial loss as defined in Section 5.6.5.1, Make-Whole Payment for Canceled or Delayed Outages for OSAs.

(b) For a Resource without RUC Instructions issued for hours during the OSA Period, ERCOT shall create RUC instructions for all hours of the OSA Period for Settlement purposes only. The created RUC instructions will be assigned to the first RUC process of each Operating Day. The RUC Guarantee shall include only the following:

(i) Approved net financial loss as defined in Section 5.6.5.1.

(c) For a Resource that rescheduled an Outage within 120 days of the end of the OSA Period under paragraph (4) of Section 3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities, the RUC Guarantee determined in paragraphs (a) and (b) above must include an OSA Make-Whole Cost (OSAMW), calculated for the same corresponding OSA Period hours, when the Outage is rescheduled due to the OSA, starting with the first day of the rescheduled Outage period. The OSAMW calculated for the rescheduled Outage hours shall be allocated to the corresponding RUC instructed hours, in paragraphs (a) or (b) above, on a day-by-day basis. The OSAMW shall be calculated as follows:

$$\text{OSAMW}_{q,\,r,\,d} = \sum_{i} (\text{Max}\ (0, (\text{RTSPP} - \text{MOC}_{q,\,r,\,h})) * \text{HSL}_{q,\,r,\,h} * (¼))$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{OSAMW}_{q,\,r,\,d}$	\$	OSA Make-Whole Cost—The OSA Make-Whole cost for Resource *r* represented by QSE *q* during the eligible rescheduled Outage Hours, for the Operating Day *d*. When one or more Combined Cycle Generation Resources receive an OSA, the Make-Whole cost is calculated for the Combined Cycle Train for the OSA Period.
RTSPP	\$/MWh	Real-Time Settlement Point Price—The Real-Time Settlement Point Price at the Settlement Point for the 15-minute Settlement Interval of an eligible rescheduled Outage Hour.
$\text{MOC}_{q,\,r,\,h}$	\$/MWh	Mitigated Offer Cap per Resource—The MOC for Resource *r* represented by QSE *q*, for the eligible rescheduled Outage hour *h* at the High Sustained Limit (HSL) as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{HSL}_{q,\,r,\,i}$	MW	High Sustained Limit—The HSL of a Generation Resource *r* represented by QSE *q* as submitted in the COP, for the hour that includes the Settlement Interval *i*. Where for a combined cycle Resource, *r* is a Combined Cycle Generation Resource.
q	none	A QSE.
r	none	A Generation Resource.
d	none	The Operating Day.
h	none	The Operating Hour.
i	none	A 15-minute Settlement Interval within the hour.

(2) Notwithstanding the clawback provisions described in Section 5.7.2, RUC Clawback Charge, the clawback percentage shall be set at 100%.

5.6.5.3 Timeline for Calculating RUC Clawback Charges for Resources Receiving OSAs

(1) Within ten Business Days after the issuance of the RTM True-Up Statement, ERCOT will issue a Miscellaneous Invoice to charge the QSE representing the Resource that has received an OSA the excess revenues not clawed back in RUC Settlements.

(2) All clawed back revenues will be paid to QSEs based on a 15-minute Load-Ratio Share basis.

5.7 Settlement for RUC Process

5.7.1 RUC Make-Whole Payment

(1) To make up the difference when the revenues that a Reliability Unit Commitment (RUC)-committed Resource receives are less than its costs as described in paragraph (2) below, ERCOT shall calculate a RUC Make-Whole Payment for that Operating Day for that Resource (whether committed by Day-Ahead RUC (DRUC) or Hourly RUC (HRUC)).

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

(1) To make up the difference when the revenues that a Reliability Unit Commitment (RUC)-committed Resource receives are less than its costs as described in paragraph (2) below, ERCOT shall calculate a RUC Make-Whole Payment for that Operating Day for that Resource (whether committed by Day-Ahead RUC (DRUC) or Hourly RUC (HRUC)). ERCOT shall not calculate or pay a RUC Make-Whole Payment for an Energy Storage Resource (ESR).

(2) ERCOT shall pay to the Qualified Scheduling Entity (QSE) for the Resource a Make-Whole Payment if the RUC Guarantee calculated in Section 5.7.1.1, RUC Guarantee, is greater than the sum of:

(a) RUC Minimum-Energy Revenue calculated in Section 5.7.1.2, RUC Minimum-Energy Revenue;

(b) Revenue less cost above Low Sustained Limited (LSL) during RUC-Committed Hours calculated in Section 5.7.1.3, Revenue Less Cost Above LSL During RUC-Committed Hours; and

(c) Revenue less cost during QSE Clawback Intervals calculated in Section 5.7.1.4, Revenue Less Cost During QSE Clawback Intervals.

(3) The RUC Make-Whole Payment to the QSE for each RUC-committed Resource, including Reliability Must-Run (RMR) Units, for each RUC-Committed Hour in an Operating Day is calculated as follows:

$$\mathbf{RUCMWAMT}_{q,r,h} = \mathbf{(-1) * Max (0, RUCG}_{q,r,d} - \mathbf{RUCMEREV}_{q,r,d} - \mathbf{RUCEXRR}_{q,r,d} - \mathbf{RUCEXRQC}_{q,r,d}\mathbf{) / RUCHR}_{q,r,d}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$RUCMWAMT_{q,r,h}$	$	*RUC Make-Whole Payment*—The RUC Make-Whole Payment to the QSE for Resource *r*, for each RUC-Committed Hour of the Operating Day. When one or more Combined Cycle Generation Resources are committed by RUC, payment is made to the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$RUCG_{q,r,d}$	$	*RUC Guarantee*—The sum of eligible Startup Costs and minimum-energy costs for Resource *r* during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.1. When one or more Combined Cycle Generation Resources are committed by RUC, guaranteed costs are calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$RUCMEREV_{q,r,d}$	$	*RUC Minimum-Energy Revenue*—The sum of the energy revenues for Resource *r*'s generation up to LSL during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.2. When one or more Combined Cycle Generation Resources are committed by RUC, minimum-energy revenue is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$RUCEXRR_{q,r,d}$	$	*Revenue Less Cost Above LSL During RUC-Committed Hours*—The sum of the total revenue for Resource *r* operating above its LSL less the cost during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.3. When one or more Combined Cycle Generation Resources are committed by RUC, revenue less cost above LSL is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$RUCEXRQC_{q,r,d}$	$	*Revenue Less Cost During QSE Clawback Intervals*—The sum of the total revenue for Resource *r* less the cost during all QSE Clawback Intervals, for the Operating Day. See Section 5.7.1.4. When one or more Combined Cycle Generation Resources are committed by RUC, revenue less cost during QSE Clawback Intervals is calculated for the Combined Cycle Train for all Combined Cycle Generation Resources earning revenue in QSE Clawback Intervals.
$RUCHR_{q,r,d}$	None	RUC Hour—The total number of RUC-Committed Hours, for Resource *r* for the Operating Day. When one or more Combined Cycle Generation Resources are committed by RUC, the total number of RUC-Committed Hours is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
q	None	A QSE.
r	None	A RUC-committed Generation Resource.
d	None	An Operating Day containing the RUC-commitment.
h	None	An hour in the RUC-commitment period.

5.7.1.1 RUC Guarantee

(1) The allowable Startup Costs and minimum-energy costs of a Resource committed by RUC is the RUC Guarantee. The RUC Guarantee minimum-energy costs are prorated according to the actual generation when the Resource's average output during a 15-minute Settlement Interval is below the corresponding LSL.

(2) The SUPR, MEPR and LSL used to calculate the RUC Guarantee for a Combined Cycle Train are the SUPR, MEPR and LSL that correspond to the Combined Cycle Generation Resource, within the Combined Cycle Train, that is RUC-committed for the hour. If the RUC-Committed Interval is a RUC for Additional Capacity (RUCAC)-Interval, then the SUPR, MEPR, and LSL that corresponds to the QSE-committed Combined Cycle Generation Resource is also used to calculate RUC Guarantee for a Combined Cycle Train.

(3) For an Aggregate Generation Resource (AGR), the Startup Cost shall be scaled according to the maximum number of its generators online during a contiguous block of RUC-committed intervals, as indicated by telemetry, compared to the total number of generators registered to the AGR and used in the approved verifiable cost for the AGR.

(4) The RUC Guarantee is calculated for non-Combined Cycle Trains as follows:

$$\mathbf{RUCG}_{q,r,d} = \sum_{s} (\mathbf{SUPR}_{q,r,s} * \mathbf{RUCSUFLAG}_{q,r,s}) + \sum_{i} (\mathbf{MEPR}_{q,r,i} * \mathbf{Min}((\mathbf{LSL}_{q,r,i} * (1/4)), \mathbf{RTMG}_{q,r,i}))$$

(5) The RUC Guarantee is calculated for Combined Cycle Trains as follows:

$$\text{RUCG}_{q,r,d} = (\text{SUPR}_{q,r,s} * \text{RUCSUFLAG}_{q,r,s}) + \sum_{t} (\text{MAX}(0, \text{SUPR} - \text{SUPR})) + \sum_{i} (\text{RUCGME}_{q,r,i})$$

Where,

If a Combined Cycle Train transitions to a RUC-committed configuration from a QSE-committed or other RUC-committed configuration between two contiguous hours, or to a RUC-committed configuration from a QSE-committed configuration within the same hour due to a RUCAC, the transition is calculated as follows:

$$\text{MAX}(0, \text{SUPR}_{afterCCGR} - \text{SUPR}_{beforeCCGR})$$

If a Combined Cycle Train transitions to a QSE-committed configuration from a RUC-committed configuration, the transition is calculated as follows:

$$\text{MAX}(0, \text{SUPR}_{beforeCCGR} - \text{SUPR}_{afterCCGR})$$

If the interval *i* is a RUC-Committed Interval that is not a RUCAC, then:

$$\text{RUCGME}_{q,\,r,\,i} = \text{MEPR}_{q,\,r,\,i} * \text{Min}\,((\text{LSL}_{q,\,r,\,i} * (1/4)),\ \text{RTMG}_{q,\,r,\,i})$$

If the interval *i* is a RUCAC of a previously QSE-Committed Interval, then:

$$\text{RUCGME}_{q,\,r,\,i} = \text{Max}\,[0,\ \text{MEPR}_{q,\,afterCCGR,\,i} * \text{Min}\,((\text{LSL}_{q,\,afterCCGR,\,i} * (1/4)),\ \text{RTMG}_{q,\,r,\,i}) - \text{MEPR}_{q,\,\text{beforeCCGR},\,i} * (\text{LSL}_{q,\,\text{beforeCCGR},\,i} * (1/4))]$$

(6) If a validated Three-Part Supply Offer has been submitted for a Resource for the RUC, then the RUC Guarantee for that Resource is based on the minimum of the Startup Offer in that validated Three-Part Supply Offer and Startup Cap and the lesser of the Minimum-Energy Offer in that validated Three-Part Supply Offer and the Minimum-Energy Offer Cap. If a validated Three-Part Supply Offer has not been submitted for a Resource for the RUC and ERCOT has not yet approved verifiable unit-specific costs for the Resource, then the RUC Guarantee for a Resource is based on the Resource Category Startup Generic Cap and the Resource Category Minimum-Energy Generic Cap. If a validated Three-Part Supply Offer has not been submitted for a Resource for the RUC and ERCOT has approved verifiable unit-specific costs for the Resource, then the RUC Guarantee for a Resource is based on the most recent ERCOT-approved verifiable unit-specific costs for that Resource.

For a Resource which is not an AGR,

If the QSE submitted a validated Three-Part Supply Offer,

Then, $\text{SUPR}_{q,\,r,\,\text{s}} = \text{Min}\,(\text{SUO}_{q,\,r,\,s},\ \text{SUCAP}_{q,\,r,\,s})$

$\text{MEPR}_{q,\,r,\,i} = \text{Min}\,(\text{MEO}_{q,\,r,\,i},\ \text{MECAP}_{q,\,r,\,i})$

Otherwise, $\text{SUPR}_{q,\,r,\,s} = \text{SUCAP}_{q,\,r,\,s}$

$\text{MEPR}_{q,\,r,\,i} = \text{MECAP}_{q,\,r,\,i}$

If ERCOT has approved verifiable Startup Costs and minimum-energy costs for the Resource,

Then, $\text{SUCAP}_{q,\,r,\,s} = \text{verifiable Startup Costs}_{q,\,r,\,s}$

$\text{MECAP}_{q,\,r,\,i} = \text{verifiable minimum-energy costs}_{q,\,r,\,i}$

Otherwise, $\text{SUCAP}_{q,\,r,\,s} = \text{RCGSC}_{s}$

$\text{MECAP}_{q,\,r,\,i} = \text{RCGMEC}_{i}$

For AGRs,

If the QSE submitted a validated Three-Part Supply Offer,

Then, $\text{SUPR}_{q,\,r,\,\text{s}} = \text{Min}\,(\text{SUO}_{q,\,r,\,s},\ \text{SUCAP}_{q,\,r,\,s})$

$\text{MEPR}_{q, r, i} = \text{Min}(\text{MEO}_{q, r, i}, \text{MECAP}_{q, r, i})$

Otherwise, $\text{SUPR}_{q, r, s} = \text{SUCAP}_{q, r, s}$

$\text{MEPR}_{q, r, i} = \text{MECAP}_{q, r, i}$

If ERCOT has approved verifiable Startup Costs and minimum-energy costs for the Resource,

Then, $\text{SUCAP}_{q, r, s} = \text{Max}_{c}(\text{AGRRATIO}_{q, p, r}) * \text{verifiable Startup Costs}_{q, r, s}$

$\text{MECAP}_{q, r, i} = \text{verifiable minimum-energy costs}_{q, r, i}$

Where, $\text{AGRRATIO}_{q, p, r} = \text{AGRMAXON}_{q, p, r} / \text{AGRTOT}_{q, p, r}$

Otherwise, $\text{SUCAP}_{q, r, s} = \text{Max}_{c}(\text{AGRRATIO}_{q, p, r}) * \text{RCGSC}_{s}$

$\text{MECAP}_{q, r, i} = \text{RCGMEC}_{i}$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{RUCG}_{q, r, d}$	$	*RUC Guarantee*—The sum of eligible Startup Costs and minimum-energy costs for Resource *r* represented by QSE *q* during all RUC-Committed Hours, for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by RUC, guaranteed costs are calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$\text{RUCGME}_{q, r, i}$	$	*RUC Minimum-Energy Guarantee by interval*—The guaranteed costs for Resource *r* represented by QSE *q* for minimum energy for the Settlement Interval *i*. When one or more Combined Cycle Generation Resources are committed by RUC, RUC Minimum-Energy Guarantee is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources. During RUCAC-Intervals for a Combined Cycle Train, minimum energy cost is calculated as the difference between the minimum energy cost between the RUC-committed configuration and the QSE-committed configuration.
$\text{SUPR}_{q, r, s}$	$/Start	*Startup Price per start*—The Settlement price for Resource *r* represented by QSE *q* for the start *s*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{SUO}_{q, r, s}$	$/Start	*Startup Offer per start*—Represents an offer for all costs incurred by Generation Resource *r* represented by QSE *q* in starting up and reaching the Resource's LSL for the start *s*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	**Unit**	**Definition**
SUCAP $_{q, r, s}$	\$/Start	*Startup Cap*—The amount used for AGR *r* or Resource *r* represented by QSE *q* for the start *s* as Startup Costs. The cap is the Resource Category Startup Offer Generic Cap (RCGSC) unless ERCOT has approved verifiable unit-specific Startup Costs for that Resource, in which case the startup cap is the scaled verifiable unit-specific Startup Cost for the AGR or the verifiable unit-specific Startup Cost for non-AGRs. The verifiable unit-specific Startup Cost will be determined as described in Section 5.6.1, Verifiable Costs, minus the average energy produced during the time period between breaker close and LSL multiplied by the heat rate proxy "H" multiplied by the appropriate Fuel Index Price (FIP), Fuel Oil Price (FOP) or solid fuel price, for AGR and non-AGR Resources. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
AGRRATIO $_{q, p, r}$	none	*Aggregate Generation Resource Ratio per QSE per Settlement Point per Aggregate Generation Resource*—A value which represents the ratio of the maximum number of generators online during an hour, as indicated by telemetry, compared to the total number of generators registered to the AGR *r* represented by QSE *q* at the Settlement Point *p* and used in the approved verifiable cost for the AGR. The value is only applicable if the Resource is an AGR.
AGRMAXON $_{q, p, r}$	none	*Aggregate Generation Resource Maximum Online per QSE per Settlement Point per Aggregate Generation Resource*—The maximum number of generators registered to the AGR *r* represented by QSE *q* at the Settlement Point *p* online during an hour, as indicated by telemetry. The value is only applicable if the Resource is an AGR.
AGRTOT $_{q, p, r}$	none	*Aggregate Generation Resource Total per QSE per Settlement Point per Aggregate Generation Resource*—The total number of generators registered to the AGR *r* represented by QSE *q* at the Settlement Point *p* and used in the approved verifiable cost for the AGR. The value is only applicable if the Resource is an AGR.
RCGSC $_{s}$	\$/Start	*Resource Category Generic Startup Cost*—The Resource Category Generic Startup Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
RUCSUFLAG $_{q, r, s}$	none	*RUC Startup Flag*—The flag that indicates whether or not the start *s* for Resource *r* represented by QSE *q* is eligible for RUC Make-Whole Payment. Its value is one if eligible; otherwise, zero. See Section 5.6.2, RUC Startup Cost Eligibility, and Section 5.6.3, Forced Outage of RUC-Committed Resource, for more information on startup eligibility. For a Combined Cycle Train, the Resource *r* must be one of the registered Combined Cycle Generation Resources within the Combined Cycle Train. When one or more Combined Cycle Generation Resources are committed by RUC, the RUC Startup Flag is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
MEPR $_{q, r, i}$	\$/MWh	*Minimum-Energy Price*—The Settlement price for Resource *r* represented by QSE *q* for minimum energy for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MEO $_{q, r, i}$	\$/MWh	*Minimum-Energy Offer*—Represents an offer for the costs incurred by Resource *r* represented by QSE *q* in producing energy at the Resource's LSL for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	Unit	Definition
MECAP $_{q,\ r,\ i}$	\$/MWh	*Minimum-Energy Cap*—The amount used for Resource *r* represented by QSE *q* for the Settlement Interval *i* for minimum-energy costs. The minimum cost is the Resource Category Minimum-Energy Generic Cap (RCGMEC) unless ERCOT has approved verifiable unit-specific minimum energy costs for that Resource, in which case the Minimum-Energy Cap is the verifiable unit-specific minimum energy cost. See Section 5.6.1 for more information on verifiable costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RCGMEC $_{i}$	\$/MWh	*Resource Category Generic Minimum-Energy Cost*—The Resource Category Generic Minimum Energy Cost cap for the category of the Resource, according to Section 4.4.9.2.3, for the Operating Day.
RTMG $_{q,\ r,\ i}$	MWh	*Real-Time Metered Generation*—The metered generation of Resource *r* represented by QSE *q* for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
LSL $_{q,\ r,\ i}$	MW	*Low Sustained Limit*—The LSL of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the Current Operating Plan (COP). Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
i	none	A 15-minute Settlement Interval within the hour that includes a RUC-commitment.
s	none	A start that is eligible to have its costs included in the RUC Guarantee.
t	none	A transition that is eligible to have its costs included in the RUC Guarantee.
c	none	A contiguous block of RUC–Committed Hours.
afterCCGR	none	The Combined Cycle Generation Resource to which a Combined Cycle Train transitions.
beforeCCGR	none	The Combined Cycle Generation Resource from which a Combined Cycle Train transitions.

5.7.1.2 RUC Minimum-Energy Revenue

(1) The energy revenue for a Resource's generation up to LSL during all RUC-Committed Hours of the Operating Day is RUC Minimum-Energy Revenue.

(2) The LSL used to calculate RUC Minimum-Energy Revenue for a Combined Cycle Train is the LSL that corresponds to the Combined Cycle Generation Resource, within the Combined Cycle Train, that is RUC-committed for the hour. If the interval is a RUCAC-Interval, then the LSL that corresponds to the QSE-committed Combined Cycle Generation Resource is also used to calculate RUC Minimum-Energy Revenue for a Combined Cycle Train.

(3) For each RUC-committed Resource, RUC Minimum-Energy Revenue is calculated as follows:

$$\mathbf{RUCMEREV}_{q,r,d} = \sum_{i} (\mathbf{RUCMEREV96}_{q,r,i})$$

Where,

If the interval *i* is a RUC-Committed Interval that is not a RUCAC-Interval, then:

$$\text{RUCMEREV96}_{q,r,i} = \text{RTSPP}_{p,i} * \text{Min}(\text{RTMG}_{q,r,i}, (\text{LSL}_{q,r,i} * (\tfrac{1}{4})))$$

If the interval *i* is a RUCAC of a previously QSE-Committed Interval, then:

$$\text{RUCMEREV96}_{q,r,i} = \text{RTSPP}_{p,i} * \text{Max}\,[0, \text{Min}(\text{RTMG}_{q,r,i}, (\text{LSL}_{q,afterCCGR,i} * (\tfrac{1}{4}))) - \text{LSL}_{q,beforeCCGR,i} * (\tfrac{1}{4})]$$

The above variables are defined as follows:

Variable	Unit	Definition
RUCMEREV $_{q,r,d}$	\$	*RUC Minimum-Energy Revenue*—The sum of the energy revenues for generation of Resource *r* represented by QSE *q* up to LSL during all RUC-Committed Hours, for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by RUC, RUC Minimum-Energy Revenue is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCMEREV96 $_{q,r,i}$	\$	*RUC Minimum-Energy Revenue by interval*—The energy revenues for generation of Resource *r* represented by QSE *q* up to LSL during all RUC-Committed Hours, for the Settlement Interval *i*. When one or more Combined Cycle Generation Resources are committed by RUC, RUC Minimum-Energy Revenue is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources. During RUCAC-Intervals for a Combined Cycle Train, the minimum energy revenue is calculated as the difference between the minimum energy revenue of the RUC-committed configuration and the QSE-committed configuration.
RTSPP $_{p,i}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource Node Settlement Point *p* for the Settlement Interval *i*.
RTMG $_{q,r,i}$	MWh	*Real-Time Metered Generation*—The metered generation of Resource *r* represented by QSE *q* for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
LSL $_{q,r,i}$	MW	*Low Sustained Limit*—The LSL of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval within the hour that includes a RUC-commitment.
afterCCGR	none	The Combined Cycle Generation Resource that is RUC-committed.
beforeCCGR	none	The Combined Cycle Generation Resource that was QSE-committed.

5.7.1.3 Revenue Less Cost Above LSL During RUC-Committed Hours

(1) The total revenue for a Resource operating above its LSL less the cost based on the Energy Offer Curve Cost Cap (as described in Section 4.4.9.3.3, Energy Offer Curve Cost Caps) during all RUC-Committed Hours of the Operating Day is Revenue Less Cost Above LSL During RUC-Committed Hours.

(2) The LSL used to calculate Revenue Less Cost Above LSL During RUC-Committed Hours for a Combined Cycle Train is the LSL that corresponds to the Combined Cycle Generation Resource, within the Combined Cycle Train, that is RUC-committed for the hour.

(3) For each RUC-committed Resource, Revenue Less Cost Above LSL During RUC-Committed Hours is calculated as follows:

$$\mathbf{RUCEXRR}_{q,\,r,\,d} = \mathbf{Max}\ \{0,\ \sum_{i} [\mathbf{RUCEXRR96}_{q,\,r,\,i}]\}$$

Where,

$$\begin{aligned}\mathbf{RUCEXRR96}_{q,\,r,\,i} = {} & \mathbf{RTSPP}_{p,\,i} * \mathbf{Max}\ (0,\ \mathbf{RTMG}_{q,\,r,\,i} - (\mathbf{LSL}_{q,\,r,\,i} * (¼))) \\ & + (-1) * (\mathbf{VSSVARAMT}_{q,\,r,\,i} + \mathbf{VSSEAMT}_{q,\,r,\,i}) \\ & + (-1) * \mathbf{EMREAMT}_{q,\,r,\,i} \\ & - \mathbf{RTEOCOST}_{q,\,r,\,i} * \mathbf{Max}\ (0,\ \mathbf{RTMG}_{q,\,r,\,i} - (\mathbf{LSL}_{q,\,r,\,i} * (¼)))]\}\end{aligned}$$

[NPRR1009, NPRR1014, and NPRR1140: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014 or NPRR1140:]

(3) For each RUC-committed Resource, Revenue Less Cost Above LSL During RUC-Committed Hours is calculated as follows:

If RUCFCA exists:

$$\mathbf{RUCEXRR}_{q,\,r,\,d} = \sum_{i} [\mathbf{RUCEXRR96}_{q,\,r,\,i}]$$

Otherwise:

$$\mathbf{RUCEXRR}_{q,\,r,\,d} = \mathbf{Max}\ \{0,\ \sum_{i} [\mathbf{RUCEXRR96}_{q,\,r,\,i}]\}$$

Where,

$$\begin{aligned}\mathbf{RUCEXRR96}_{q,r,i} = {} & \mathbf{RTSPP}_{p,i} * \mathbf{Max}\ (\mathbf{0}, \mathbf{RTMG}_{q,r,i} - (\mathbf{LSL}_{q,r,i} * (\tfrac{1}{4}))) \\ & \quad + \mathbf{RTASREV}_{q,r,i} \\ & + (-1) * (\mathbf{VSSVARAMT}_{q,r,i} + \mathbf{VSSEAMT}_{q,r,i}) \\ & + (-1) * \mathbf{EMREAMT}_{q,r,i} \\ & - (\mathbf{RTEOCOST}_{q,r,i} + \mathbf{RUCFCA}_{q,r,i}) * \mathbf{Max}\ (\mathbf{0}, \mathbf{RTMG}_{q,r,i} - \\ & \quad (\mathbf{LSL}_{q,r,i} * (\tfrac{1}{4})))\end{aligned}$$

Where,

$$\mathrm{RTASREV}_{q,r,i} = \mathrm{RTRUREV}_{q,r,i} + \mathrm{RTRDREV}_{q,r,i} + \mathrm{RTRRREV}_{q,r,i} + \mathrm{RTECRREV}_{q,r,i} + \mathrm{RTNSREV}_{q,r,i}$$

And,

$$\mathrm{RUCFCA}_{q,r,i} = \mathrm{Max}(0, \text{Volume-weighted average actual fuel price}_{q,r,i} * \text{Average heat rate} - \mathrm{RTEOCOST}_{q,r,i})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\mathrm{RUCEXRR}_{q,r,d}$	\$	*Revenue Less Cost Above LSL During RUC-Committed Hours*—The sum of the total revenue for Resource *r* represented by QSE *q* operating above its LSL less the cost during all RUC-Committed Hours, for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by RUC, revenue less cost above LSL is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$\mathrm{RUCEXRR96}_{q,r,i}$	\$	*Revenue Less Cost Above LSL During RUC-Committed Hours by interval*—The total revenue for Resource *r* represented by QSE *q* operating above its LSL less the cost during all RUC-Committed hours, for the Settlement Interval *i*. When one or more Combined Cycle Generation Resources are committed by RUC, revenue less cost above LSL is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$\mathrm{RTSPP}_{p,i}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource's Resource Node Settlement Point *p* for the Settlement Interval *i*.
$\mathrm{RTEOCOST}_{q,r,i}$	\$/MWh	*Real-Time Energy Offer Curve Cost Cap*—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\mathrm{RTMG}_{q,r,i}$	MWh	*Real-Time Metered Generation*—The metered generation of Resource *r* represented by QSE *q* for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition

[NPRR1140: Insert the variable "RUCFCA $_{q, r, i}$" below upon system implementation:]

RUCFCA $_{q, r, i}$	\$/MWh	*Reliability Unit Commitment Fuel Cost Adder*—For a QSE that has been granted a fuel dispute per Section 9.14.7, Disputes for RUC Make-Whole Payment for Fuel Costs, the fuel cost adder is calculated as the volume-weighted average actual fuel price times the output-level average heat rate for Resource *r* represented by QSE *q*, for the Resource's generation above LSL, for the Settlement Interval *i*, minus the RTEOCOST. When one or more Combined Cycle Generation Resources are committed by RUC, RUCFCA is calculated for the Combined Cycle Train for all RUC-Committed Combined Cycle Generation Resources. The average heat rate for the Resource is the Average Heat Rate at the output level at Settlement Interval *i*, resulting from the input-output coefficients submitted with verifiable costs, if available, otherwise the heat rate value defined in Section 4.4.9.3.3. The volume-weighted average actual fuel price must be proven by the QSE by submitting a dispute per Section 9.14.7.

LSL $_{q, r, i}$	MW	*Low Sustained Limit*—The LSL of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

[NPRR1009 and NPRR1014: Insert applicable variables below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]

RTASREV $_{q, r, i}$	\$	*Real-Time Ancillary Service Revenue* — The total Real-Time Ancillary Service revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRUREV $_{q, r, i}$	\$	*Real-Time Reg-Up Revenue* — The Real-Time Reg-Up revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDREV $_{q, r, i}$	\$	*Real-Time Reg-Down Revenue* — The Real-Time Reg-Down revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRRREV $_{q, r, i}$	\$	*Real-Time Responsive Reserve Revenue* — The Real-Time RRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTNSREV $_{q, r, i}$	\$	*Real-Time Non-Spin Revenue* — The Real-Time Non-Spin revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTECRREV $_{q, r, i}$	\$	*Real-Time ERCOT Contingency Reserve Service Revenue* — The Real-Time ECRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition
VSSVARAMT $_{q, r, i}$	$	*Voltage Support Service VAr Amount by interval*—The payment to the QSE *q* for the Voltage Support Service (VSS) provided by Generation Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments. Payment for VSS is made to the Combined Cycle Train. ***[NPRR1009 and NPRR1014: Replace applicable portions of the definition above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]*** *Voltage Support Service VAr Amount*—The payment to the QSE *q* for the Voltage Support Service (VSS) provided by Generation Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments. Payment for VSS is made to the Combined Cycle Train.
VSSEAMT $_{q, r, i}$	$	*Voltage Support Service Energy Amount by interval*—The lost opportunity payment to the QSE *q* for ERCOT-directed VSS from the Generation Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.6.7.1. Payment for emergency energy is made to the Combined Cycle Train. ***[NPRR1009 and NPRR1014: Replace applicable portions of the definition above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]*** *Voltage Support Service Energy Amount*—The lost opportunity payment to the QSE *q* for ERCOT-directed VSS from the Generation Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.6.7.1. Payment for emergency energy is made to the Combined Cycle Train.
EMREAMT $_{q, r, i}$	$	*Emergency Energy Amount by interval*—The payment to the QSE *q* as additional compensation for the additional energy produced by the Generation Resource *r* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval *i*. See Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT. Payment for emergency energy is made to the Combined Cycle Train. ***[NPRR1009 and NPRR1014: Replace applicable portions of the definition above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]*** *Emergency Energy Amount*—The payment to the QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by the Resource *r* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval *i*. See Section 6.6.9.1, Payment for Emergency Operations Settlement. Payment for emergency energy is made to the Combined Cycle Train.
q	none	A QSE.

Variable	Unit	Definition
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval within the hour that includes a RUC instruction.

5.7.1.4 Revenue Less Cost During QSE Clawback Intervals

(1) The total revenue for a Resource less the cost based on the Energy Offer Curve Cost Cap as described in Section 4.4.9.3.3, Energy Offer Curve Cost Caps, during all QSE Clawback Intervals of the Operating Day is Revenue Less Cost During QSE-Clawback Intervals.

(2) The MEPR and LSL used to calculate Revenue Less Cost During QSE Clawback Intervals for a Combined Cycle Train is the MEPR and LSL that corresponds to the Combined Cycle Generation Resource, within a Combined Cycle Train, that operates in Real-Time for the QSE Clawback Interval.

(3) For each QSE Clawback Interval, Revenue Less Cost During QSE Clawback Intervals is calculated as follows:

$$\mathbf{RUCEXRQC}_{q,r,d} = \mathbf{Max}\ \{0, \sum_{i} [(\mathbf{RTSPP}_{p,i} * \mathbf{RTMG}_{q,r,i}) + (-1) * (\mathbf{VSSVARAMT}_{q,r,i} + \mathbf{VSSEAMT}_{q,r,i}) + (-1) * \mathbf{EMREAMT}_{q,r,i} - [\mathbf{MEPR}_{q,r,i} * \mathbf{Min}\ (\mathbf{RTMG}_{q,r,i}, (\mathbf{LSL}_{q,r,i} * (1/4)))] - [\mathbf{RTEOCOST}_{q,r,i} * \mathbf{Max}\ (0, \mathbf{RTMG}_{q,r,i} - (\mathbf{LSL}_{q,r,i} * (1/4)))]]\}$$

If the QSE submitted a validated Three-Part Supply Offer for the Resource,

Then, $\text{MEPR}_{q,r,i} = \text{Min}\ (\text{MEO}_{q,r,i}, \text{MECAP}_{q,r,i})$

Otherwise, $\text{MEPR}_{q,r,i} = \text{MECAP}_{q,r,i}$

If ERCOT has approved verifiable minimum-energy costs for the Resource,

Then, $\text{MECAP}_{q,r,i} = \text{verifiable minimum-energy costs}_{q,r,i}$

Otherwise, $\text{MECAP}_{q,r,i} = \text{RCGMEC}_{i}$

[NPRR1009 and NPRR1014: Replace applicable portions of the formula "RUCEXRQC $_{q, r, d}$" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]

$$\mathbf{RUCEXRQC}_{q, r, d} = \mathbf{Max}\ \{0, \sum_{i} [(\mathbf{RTSPP}_{p, i} * \mathbf{RTMG}_{q, r, i}) + \mathbf{RTASREV}_{q, r, i} + (-1) * (\mathbf{VSSVARAMT}_{q, r, i} + \mathbf{VSSEAMT}_{q, r, i}) + (-1) * \mathbf{EMREAMT}_{q, r, i} - [\mathbf{MEPR}_{q, r, i} * \mathbf{Min}\ (\mathbf{RTMG}_{q, r, i}, (\mathbf{LSL}_{q, r, i} * (¼)))] - [\mathbf{RTEOCOST}_{q, r, i} * \mathbf{Max}\ (0, \mathbf{RTMG}_{q, r, i} - (\mathbf{LSL}_{q, r, i} * (¼)))]]\}$$

If the QSE submitted a validated Three-Part Supply Offer for the Resource,

Then, $\text{MEPR}_{q, r, i} = \text{Min}\ (\text{MEO}_{q, r, i}, \text{MECAP}_{q, r, i})$

Otherwise, $\text{MEPR}_{q, r, i} = \text{MECAP}_{q, r, i}$

If ERCOT has approved verifiable minimum-energy costs for the Resource,

Then, $\text{MECAP}_{q, r, i} = \text{verifiable minimum-energy costs}_{q, r, i}$

Otherwise, $\text{MECAP}_{q, r, i} = \text{RCGMEC}_{i}$

Where,

$$\text{RTASREV}_{q, r, i} = \text{RTRUREV}_{q, r, i} + \text{RTRDREV}_{q, r, i} + \text{RTRRREV}_{q, r, i} + \text{RTECRREV}_{q, r, i} + \text{RTNSREV}_{q, r, i}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
RUCEXRQC $_{q, r, d}$	$	*Revenue Less Cost During QSE-Clawback Intervals*—The sum of the total revenue for Resource *r* less the cost during all QSE-Clawback Intervals for the Operating Day. When one or more Combined Cycle Generation Resources are committed by RUC, Revenue Less Cost During QSE-Clawback Intervals is calculated for the Combined Cycle Train for all Combined Cycle Generation Resources earning revenue in QSE-Clawback Intervals.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource's Settlement Point for the Settlement Interval *i*.

Variable	**Unit**	**Definition**
MEPR $_{q, r, i}$	$/MWh	*Minimum-Energy Price*—The Settlement price for Resource *r* for minimum energy for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MEO $_{q, r, i}$	$/MWh	*Minimum-Energy Offer*—Represents an offer for the costs incurred by Resource *r* in producing energy at the Resource's LSL for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MECAP $_{q, r, i}$	$/MWh	*Minimum-Energy Cap*—The amount used for Resource *r* for minimum-energy costs. The minimum cost is the Resource Category Minimum-Energy Generic Cap (RCGMEC) unless ERCOT has approved verifiable unit-specific minimum energy costs for that Resource, in which case the Minimum-Energy Cap is the verifiable unit-specific minimum energy cost. See Section 5.6.1, Verifiable Costs, for more information on verifiable costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RCGMEC $_{i}$	$/MWh	*Resource Category Generic Minimum-Energy Cost*—The Resource Category Generic Minimum-Energy Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
RTEOCOST $_{q, r, i}$	$/MWh	*Real-Time Energy Offer Curve Cost Cap*—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource's generation above the LSL for the Settlement Interval *i.* See Section 4.4.9.3.3. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMG $_{q, r, i}$	MWh	*Real-Time Metered Generation*—The Resource *r*'s metered generation for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
LSL $_{q, r, i}$	MW	*Low Sustained Limit*—The LSL of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

<table>
<tr><th>Variable</th><th>Unit</th><th>Definition</th></tr>
<tr><td colspan="3">***[NPRR1009 and NPRR1014: Insert applicable portions of the variables below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]***</td></tr>
<tr><td>$\text{RTASREV}_{q, r, i}$</td><td>$</td><td>*Real-Time Ancillary Service Revenue* — The total Real-Time Ancillary Service revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</td></tr>
<tr><td>$\text{RTRUREV}_{q, r, i}$</td><td>$</td><td>*Real-Time Reg-Up Revenue* — The Real-Time Reg-Up revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</td></tr>
<tr><td>$\text{RTRDREV}_{q, r, i}$</td><td>$</td><td>*Real-Time Reg-Down Revenue* — The Real-Time Reg-Down revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</td></tr>
<tr><td>$\text{RTRRREV}_{q, r, i}$</td><td>$</td><td>*Real-Time Responsive Reserve Revenue* — The Real-Time RRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</td></tr>
<tr><td>$\text{RTNSREV}_{q, r, i}$</td><td>$</td><td>*Real-Time Non-Spin Revenue* — The Real-Time Non-Spin revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</td></tr>
<tr><td>$\text{RTECRREV}_{q, r, i}$</td><td>$</td><td>*Real-Time ERCOT Contingency Reserve Service Revenue* — The Real-Time ECRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</td></tr>
<tr><td>$\text{VSSVARAMT}_{q, r, i}$</td><td>$</td><td>*Voltage Support Service VAr Amount by interval*—The payment to the QSE for the VSS provided by Generation Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments. Payment for VSS is made to the Combined Cycle Train.
[NPRR1009 and NPRR1014: Replace applicable portions of the definition above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]
Voltage Support Service VAr Amount—The payment to the QSE for the VSS provided by Generation Resource *r* for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments. Payment for VSS is made to the Combined Cycle Train.</td></tr>
</table>

Variable	Unit	Definition
$\text{VSSEAMT}_{q, r, i}$	$	*Voltage Support Service Energy Amount by interval*—The lost opportunity payment to the QSE for ERCOT-directed VSS from the Generation Resource r for the 15-minute Settlement Interval i. See Section 6.6.7.1. Payment for VSS is made to the Combined Cycle Train. ***[NPRR1009 and NPRR1014: Replace applicable portions of the definition above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]*** *Voltage Support Service Energy Amount*—The lost opportunity payment to the QSE for ERCOT-directed VSS from the Generation Resource r for the 15-minute Settlement Interval i. See Section 6.6.7.1. Payment for VSS is made to the Combined Cycle Train.
$\text{EMREAMT}_{q, r, i}$	$	*Emergency Energy Amount by interval*—The payment to the QSE as additional compensation for the additional energy produced by the Generation Resource r in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval i. See Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT. Payment for emergency energy is made to the Combined Cycle Train. ***[NPRR1009 and NPRR1014: Replace applicable portions of the definition above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]*** *Emergency Energy Amount*—The payment to the QSE as additional compensation for the additional energy or Ancillary Services produced or consumed by the Resource r in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval i. See Section 6.6.9.1, Payment for Emergency Operations Settlement. Payment for emergency energy is made to the Combined Cycle Train.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval within the hour that is identified as a QSE-Clawback Interval.

5.7.2 RUC Clawback Charge

(1) A QSE for a Resource shall pay a RUC Clawback Charge for the Operating Day if the RUC Guarantee is less than the sum of:

(a) RUC Minimum-Energy Revenue calculated in Section 5.7.1.2, RUC Minimum-Energy Revenue;

(b) Revenue Less Cost Above LSL During RUC-Committed Hours calculated in Section 5.7.1.3, Revenue Less Cost Above LSL During RUC-Committed Hours; and

(c) Revenue Less Cost During QSE-Clawback Intervals calculated in Section 5.7.1.4, Revenue Less Cost During QSE Clawback Intervals.

(2) The amount of the RUC Clawback Charge is a percentage of the difference calculated in paragraph (1) above. Whether or not the QSE submits a Three-Part Supply Offer for a Resource in the Day Ahead Market (DAM) determines if that Resource will have a clawback applied in its Settlement. If the QSE submitted a validated Three-Part Supply Offer for the Resource into the DAM, then the clawback percentage in RUC Committed Hours is 50% and the clawback percentage in QSE Clawback Intervals is 0%. If not, then the clawback percentage in RUC Committed Hours is 100% and the clawback percentage in QSE Clawback Intervals is 50%.

(3) If an Energy Emergency Alert (EEA) is in effect for any period of the Operating Day, then in all RUC Committed Hours and all QSE Clawback Intervals of the Operating Day the clawback percentage is 0% if the QSE submitted a validated Three Part Supply Offer for the Resource into the DAM and 50% otherwise.

(4) For Combined Cycle Trains, if at least one Combined Cycle Generation Resource is offered into the DAM, then the Combined Cycle Train is considered to be offered into the DAM.

(5) The RUC Clawback Charge for a Resource, including RMR Units, for each Operating Day is allocated evenly over the RUC-Committed Hours for that Resource.

[NPRR1014: Insert paragraph (6) below upon system implementation and renumber accordingly:]

(6) Energy Storage Resources (ESRs) are not subject to RUC Clawback Charges.

(6) For each RUC-committed Resource, the RUC Clawback Charge for each RUC-Committed Hour of the Operating Day is calculated as follows:

If $(\text{RUCMEREV}_{q,r,d} + \text{RUCEXRR}_{q,r,d} - \text{RUCACREV}_{q,r,d} - \text{RUCG}_{q,r,d}) > 0$,

Then,

$$\mathbf{RUCCBAMT}_{q,r,h} = [(\mathbf{RUCMEREV}_{q,r,d} + \mathbf{RUCEXRR}_{q,r,d} - \mathbf{RUCACREV}_{q,r,d} - \mathbf{RUCG}_{q,r,d}) * \mathbf{RUCCBFR}_{q,r,d} + \mathbf{RUCEXRQC}_{q,r,d} * \mathbf{RUCCBFC}_{q,r,d}] / \mathbf{RUCHR}_{q,r,d}$$

Otherwise,

$$\textbf{RUCCBAMT}_{q,r,h} = [\textbf{Max}(0, \textbf{RUCMEREV}_{q,r,d} + \textbf{RUCEXRR}_{q,r,d} + \textbf{RUCEXRQC}_{q,r,d} - \textbf{RUCACREV}_{q,r,d} - \textbf{RUCG}_{q,r,d}) * \textbf{RUCCBFC}_{q,r,d}] / \textbf{RUCHR}_{q,r,d}$$

Where,

The RUCAC revenue is calculated for a Combined Cycle Train as follows:

$$\textbf{RUCACREV}_{q,r,d} = \textbf{Max}\{0, \sum_{i} \textbf{RUCMEREV96}_{q,r,i} + \textbf{Max}(0, \sum_{i} \textbf{RUCEXRR96}_{q,r,i})\}$$

The above variables are defined as follows:

Variable	Unit	Definition
RUCCBAMT $_{q, r, h}$	$	*RUC Clawback Charge*—The RUC Clawback Charge to a QSE for Resource *r* represented by QSE *q* as described in this Section, for each RUC-Committed Hour *h* of the Operating Day for that Resource. When one or more Combined Cycle Generation Resources are committed by RUC, a charge is made to the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCG $_{q, r, d}$	$	*RUC Guarantee*—The sum of eligible Startup Costs and Minimum-Energy Costs for Resource *r* represented by QSE *q* during all RUC-Committed Hours, for the Operating Day *d*. See Section 5.7.1.1, RUC Guarantee. When one or more Combined Cycle Generation Resources are committed by RUC, guaranteed costs are calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCMEREV $_{q, r, d}$	$	*RUC Minimum-Energy Revenue*—The sum of the energy revenues for generation of Resource *r* represented by QSE *q* up to LSL during all RUC-Committed Hours, for the Operating Day *d*. See Section 5.7.1.2. When one or more Combined Cycle Generation Resources are committed by RUC, RUC Minimum-Energy Revenue is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCEXRR $_{q, r, d}$	$	*Revenue Less Cost Above LSL During RUC-Committed Hours*—The sum of the total revenue for Resource *r* represented by QSE *q* above the LSL less the cost during all RUC-Committed Hours, for the Operating Day *d*. See Section 5.7.1.3. When one or more Combined Cycle Generation Resources are committed by RUC, Revenue Less Cost Above LSL During RUC-Committed Hours is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCEXRQC $_{q, r, d}$	$	*Revenue Less Cost from QSE-Clawback Intervals*—The sum of the total revenue for Resource *r* represented by QSE *q* less the cost during all QSE-Clawback Intervals for the Operating Day *d*. See Section 5.7.1.4. When one or more Combined Cycle Generation Resources are committed by RUC, Revenue Less Cost from QSE-Clawback Intervals is calculated for the Combined Cycle Train for all Combined Cycle Generation Resources earning revenue in QSE Clawback Intervals.

Variable	Unit	Definition
RUCACREV $_{q, r, d}$	$	*Revenue from RUCAC Hours*—The net positive sum for the energy revenues for generation of Resource *r* represented by QSE *q* up to LSL and the total revenue for Resource *r* operating above its LSL less the cost during all RUCAC-Hours, for the Operating Day *d*. When one or more Combined Cycle Generation Resources are RUCAC, revenue from RUCAC Hours is calculated for the Combined Cycle Train for all Combined Cycle Generation Resources that were RUC-committed during the RUCAC-Hours.
RUCMEREV96 $_{q, r, i}$	$	*RUC Minimum-Energy Revenue by Interval*—The energy revenues for generation of Resource *r* represented by QSE *q* up to LSL during all RUC-Committed Hours, for the Settlement Interval *i*. When one or more Combined Cycle Generation Resources are committed by RUC, RUC Minimum-Energy Revenue is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources. During RUCAC-Intervals for a Combined Cycle Train, the minimum energy revenue is calculated as the difference between the minimum energy revenue of the RUC-committed configuration and the QSE-committed configuration.
RUCEXRR96 $_{q, r, i}$	$	*Revenue Less Cost Above LSL During RUC-Committed Hours by Interval*—The total revenue for Resource *r* represented by QSE *q* operating above its LSL less the cost during all RUC-Committed hours, for the Settlement Interval *i*. When one or more Combined Cycle Generation Resources are committed by RUC, revenue less cost above LSL is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCCBFR $_{q, r, d}$	none	*RUC Clawback Factor for RUC-Committed Hours*—The Clawback Factor for Resource *r* represented by QSE *q* for RUC-Committed Hours, as specified in paragraphs (2) and (3) above, for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by RUC, the RUC Clawback Factor for RUC-Committed Hours is determined for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCCBFC $_{q, r, d}$	none	*RUC Clawback Factor for QSE Clawback Intervals*—The Clawback Factor for Resource *r* represented by QSE *q* for QSE Clawback Intervals, as specified in paragraphs (2) and (3) above, for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by RUC, the RUC Clawback Factor for QSE Clawback Intervals is determined for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
RUCHR $_{q, r, d}$	none	*RUC Hour*—The total number of RUC-Committed Hours, for Resource *r* represented by QSE *q* for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by RUC, the total number of RUC-Committed Hours is calculated for the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
h	none	An hour in the RUC-commitment period.
i	none	A 15-minute Settlement Interval within the hour that includes a RUCAC instruction.

5.7.3 Payment When ERCOT Decommits a QSE-Committed Resource

(1) If ERCOT decommits a QSE-committed Resource during the RUC process earlier than its scheduled shutdown within the Operating Day, then no compensation is due to the affected QSE from ERCOT.

(2) If ERCOT decommits a QSE committed Resource that is not scheduled to shutdown within the Operating Day, then ERCOT shall pay the affected QSE an amount as calculated below for the hours of decommitment. The number of continuous decommitted hours used in the calculation are the hours beginning with the first decommitted hour until the earlier of:

(a) The hour ERCOT determines that the Resource may again be at LSL; and

(b) The end of the last hour of the Operating Day.

(3) If ERCOT decommits a QSE-committed Resource not scheduled to shutdown within the Operating Day, and the decommitment period spans more than one Operating Day, the RUC Decommitment Payment Amount shall be calculated and paid in the Operating Day in which the RUC decommitment originated. The number of continuous decommitted hours used in the calculation are the hours beginning with the first decommitted hour until the end of the last hour of the Operating Day in which the RUC decommitment originated.

(4) The payment for a RUC Cancellation instruction for a Resource is settled for each hour through an adjustment in the RUC Decommitment Payment Amount as shown in paragraph (8) below.

(5) ERCOT shall produce a report each April that provides the percentage of the RUC Decommitment Payment Amounts that are a result of RUC cancellations during the 12 months of the previous calendar year. The report shall be based on the Final Settlements. ERCOT shall present the results of this study to the appropriate Technical Advisory Committee (TAC) subcommittee. If there are no RUC Decommitment Payment Amounts for a given calendar year, then ERCOT will not be required to produce the annual report.

(6) The SUPR, MEPR and LSL used to calculate payment when ERCOT decommits a QSE-committed Combined Cycle Train is the SUPR, MEPR and LSL that corresponds to the Combined Cycle Generation Resource, within the Combined Cycle Train, that is RUC-decommitted in the first hour of a contiguous decommitted period.

(7) If the SUPR used to calculate payment when ERCOT decommits a QSE-committed AGR is based upon approved verifiable cost for all of the generators associated with the AGR, ERCOT shall scale the startup payment according to the number of generators of the AGR that started following the decommitment. ERCOT shall make the adjustment no later than on Final Settlement.

(8) The payment for a RUC decommitment instruction for a Resource, including RMR Units, is calculated for each hour as follows:

[NPRR1014: Replace paragraph (8) above with the following upon system implementation:]

(8) The payment for a RUC decommitment instruction for a Resource, including RMR Units and excluding ESRs, is calculated for each hour as follows:

$$\mathbf{RUCDCAMT}_{q,r,h} = \mathbf{(-1) * Max\ (0,\ (SUPR}_{q,r,s}\ \mathbf{-}\ \sum_{i}\mathbf{(Max\ (0,\ MEPR}_{q,r,i}\ \mathbf{-\ RTSPP}_{p,i}\mathbf{)\ *\ (LSL}_{q,r,i}\ \mathbf{*\ (¼)))))\ /\ NCDCHR}_{q,r,h}$$

Where:

If the QSE submitted a validated Three-Part Supply Offer for the Resource,

Then, $\text{SUPR}_{q,r,s}$ = Min ($\text{SUO}_{q,r,s}$, SUCAP $_{q,r,s}$)

$\text{MEPR}_{q,r,i}$ = Min ($\text{MEO}_{q,r,i}$, MECAP $_{q,r,i}$)

Otherwise, $\text{SUPR}_{q,r,s}$ = $\text{SUCAP}_{q,r,s}$

$\text{MEPR}_{q,r,i}$ = $\text{MECAP}_{q,r,i}$

If ERCOT has approved verifiable Startup Costs and minimum-energy costs for the Resource,

Then, $\text{SUCAP}_{q,r,s}$ = verifiable Startup Costs$_{q,r,s}$

$\text{MECAP}_{q,r,i}$ = verifiable minimum-energy costs$_{q,r,i}$

Otherwise, $\text{SUCAP}_{q,r,s}$ = RCGSC_{s}

$\text{MECAP}_{q,r,i}$ = RCGMEC_{i}

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{RUCDCAMT}_{q,r,h}$	$	*RUC Decommitment Payment Amount*—The payment to the QSE for the Resource that was decommitted by ERCOT but that was not scheduled to shut down in the Operating Day, for each decommitted hour of the Operating Day. When one or more Combined Cycle Generation Resources are decommitted by RUC, payment is made to the Combined Cycle Train for all RUC-decommitted Combined Cycle Generation Resources.
$\text{SUPR}_{q,r,s}$	$/Start	*Startup Price per start*—The Settlement price for Resource *r* for the start *s*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	**Unit**	**Definition**
$\text{SUO}_{q,r,s}$	$/Start	*Startup Offer per start*—Represents an offer for all costs incurred by Generation Resource *r* in starting up and reaching the Resource's LSL. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{SUCAP}_{q,r,s}$	$/Start	*Startup Cap*—The amount used for Resource *r* as Startup Costs. The cap is the Resource Category Startup Offer Generic Cap (RCGSC) unless ERCOT has approved verifiable unit-specific Startup Costs for that Resource, in which case the Startup Cap is the verifiable unit-specific Startup Cost. The verifiable unit-specific Startup Cost will be determined as described in Section 5.6.1, Verifiable Costs, minus the average energy produced during the time period between breaker close and LSL multiplied by the heat rate proxy "H" multiplied by the appropriate FIP, FOP, or solid fuel price. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RCGSC_{s}	$/Start	*Resource Category Generic Startup Cost*—The Resource Category Startup Offer Generic Cap cost for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$\text{MEPR}_{q,r,i}$	$/MWh	*Minimum-Energy Price*—The Settlement price for Resource *r* for minimum energy for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{MEO}_{q,r,i}$	$/MWh	*Minimum-Energy Offer*—Represents an offer for the costs incurred by Resource *r* in producing energy at the Resource's LSL for the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{MECAP}_{q,r,i}$	$/MWh	*Minimum-Energy Cap*—The amount used for Resource *r* for minimum-energy costs. The minimum cost is the Resource Category Minimum-Energy Generic Cap (RCGMEC) unless ERCOT has approved verifiable unit-specific minimum energy costs for that Resource, in which case the Minimum-Energy Cap is the verifiable unit-specific minimum energy cost. See Section 5.6.1 for more information on verifiable costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RCGMEC_{i}	$/MWh	*Resource Category Generic Minimum-Energy Cost*—The Resource Category Minimum-Energy Generic Cap cost for the category of the Resource, according to Section 4.4.9.2.3.
$\text{LSL}_{q,r,i}$	MW	*Low Sustained Limit*—The LSL of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTSPP}_{p,i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource's Settlement Point for the Settlement Interval *i*.
$\text{NCDCHR}_{q,r,h}$	none	*Number of Continuous Decommitted Hours*—The number of continuous decommitment hours for Resource *r* within an Operating Day. When one or more Combined Cycle Generation Resources are decommitted by RUC, the Number of Continuous Decommitted Hours is calculated for the Combined Cycle Train for all RUC-decommitted Combined Cycle Generation Resources.
q	none	A QSE.
r	none	A RUC-decommitted Generation Resource.
h	none	An hour in the RUC decommitment period.
p	none	A Resource Node Settlement Point.
s	none	A start.

Variable	Unit	Definition
i	none	A 15-minute Settlement Interval within the contiguous decommitted period.

5.7.4 RUC Make-Whole Charges

(1) All QSEs that were capacity-short in each RUC will be charged for that shortage, as described in Section 5.7.4.1, RUC Capacity-Short Charge. If the revenues from the charges under Section 5.7.4.1 are not enough to cover all RUC Make-Whole Payments for a Settlement Interval, then the difference will be uplifted to all QSEs on a Load Ratio Share (LRS) basis, as described in Section 5.7.4.2, RUC Make-Whole Uplift Charge.

(2) On a monthly basis, within ten days after the Initial Settlement of the last day of the month has been completed, ERCOT shall post on the Market Information System (MIS) Secure Area the total RUC Make-Whole Charges and RUC Clawback Payment Amounts, by Settlement Interval, by QSE capacity-shortfall and by amount uplifted.

5.7.4.1 RUC Capacity-Short Charge

(1) The dollar amount charged to each QSE, due to capacity shortfalls for a particular RUC, for a 15-minute Settlement Interval, is the QSE’s shortfall ratio share multiplied by the total RUC Make-Whole Payments, including amounts for RMR Units, to all QSEs for that RUC, subject to a cap. The cap on the charge to each QSE is two multiplied by the total RUC Make-Whole Payments, including amounts for RMR Units, for all QSEs multiplied by that QSE’s capacity shortfall for that RUC process divided by the total capacity of all RUC-committed Resources during that Settlement Interval for the RUC process. That dollar amount charged to each QSE is calculated as follows:

$$\textbf{RUCCSAMT}_{ruc,\,i,\,q} = \textbf{(-1) * Max [(RUCSFRS}_{ruc,\,i,\,q} \textbf{ * RUCMWAMTRUCTOT}_{ruc,\,h}\textbf{), (2 * RUCSF}_{ruc,\,i,\,q} \textbf{ * RUCMWAMTRUCTOT}_{ruc,\,h} \textbf{ / RUCCAPTOT}_{ruc,\,h}\textbf{)] / 4}$$

Where:

$$\text{RUCMWAMTRUCTOT}_{ruc,\,h} = \sum_{q}\sum_{r} \text{RUCMWAMT}_{ruc,\,q,\,r,\,h}$$

$$\text{RUCCAPTOT}_{ruc,\,h} = \sum_{r} (\text{HSL}_{ruc,\,h,\,r} - \text{HSL}_{ruc,\,h,\,beforeCCGR})$$

[NPRR1139: Replace the formula “RUCCAPTOT $_{ruc,\,h}$***” above with the following upon system implementation:]***

$$\text{RUCCAPTOT}_{ruc,\,h} = \sum_{r} (\text{RUCHSL}_{ruc,\,h,\,r} - \text{RUCHSL}_{ruc,\,h,\,beforeCCGR})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RUCCSAMT}_{ruc,\, i,\, q}$	$	*RUC Capacity-Short Amount*—The charge to a QSE *q*, due to capacity shortfall for a particular RUC process *ruc*, for the 15-minute Settlement Interval *i*.
$\text{RUCMWAMTRUCTOT}_{ruc,\, h}$	$	*RUC Make-Whole Amount Total per RUC*—The sum of RUC Make-Whole Payments for a particular RUC process *ruc*, including amounts for RMR Units, for the hour *h* that includes the 15-minute Settlement Interval.
$\text{RUCMWAMT}_{ruc,\, q,\, r,\, h}$	$	*RUC Make-Whole Payment*—The RUC Make-Whole Payment to the QSE *q* for Resource *r*, for a particular RUC process *ruc*, for the hour *h* that includes the 15-minute Settlement Interval. See Section 5.7.1, RUC Make-Whole Payment. When one or more Combined Cycle Generation Resources are committed by RUC, payment is made to the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$\text{RUCSFRS}_{ruc,\, i,\, q}$	none	*RUC Shortfall Ratio Share*—The ratio of the QSE *q*'s capacity shortfall to the sum of all QSEs' capacity shortfalls for a particular RUC process *ruc*, for the 15-minute Settlement Interval *i*. See Section 5.7.4.1.1, Capacity Shortfall Ratio Share.
$\text{RUCSF}_{ruc,\, i,\, q}$	MW	*RUC Shortfall*—The QSE *q*'s capacity shortfall for a particular RUC process *ruc* for the 15-minute Settlement Interval *i*. See formula in Section 5.7.4.1.1.
$\text{RUCCAPTOT}_{ruc,\, h}$	MW	*RUC Capacity Total*—The sum of the High Sustained Limits (HSLs) of all RUC-committed Resources for a particular RUC process *ruc*, for the hour *h* that includes the 15-minute Settlement Interval. See formula in Section 5.7.4.1.1.
$\text{HSL}_{ruc,\, h,\, r}$	MW	*High Sustained Limit*—The HSL of Generation Resource *r* for a particular RUC process *ruc*, for the hour *h* that includes the Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

[NPRR1139: Replace the variable "HSL $_{ruc,\, h,\, r}$" above with the following upon system implementation:]

$\text{RUCHSL}_{ruc,\, q,\, r,\, h}$	MW	*High Sustained Limit at RUC Snapshot*—The HSL of Generation Resource *r* represented by QSE *q* for the hour *h*, according to the COP and Trades Snapshot for the RUC process *ruc*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

ruc	none	The RUC process for which the RUC Capacity-Short Charge is calculated.
i	none	A 15-minute Settlement Interval.
q	none	A QSE.
h	none	The hour that includes the Settlement Interval *i*.
r	none	A Generation Resource that is RUC-committed for the hour that includes the Settlement Interval *i*, as a result of a particular RUC process.

Variable	Unit	Definition
beforeCCGR	none	The Combined Cycle Generation Resource that was QSE-committed in a RUCAC-Interval.

5.7.4.1.1 Capacity Shortfall Ratio Share

(1) In calculating the amount short for each QSE, 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, shall be considered the available capacity of the WGR or PVGR when determining responsibility for the corresponding RUC charges, regardless of the Real-Time output of the WGR or PVGR. Therefore, the HASLSNAP variable used below shall be equal to the WGRPP and PVGRPP described above.

(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:

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

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:

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

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

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

(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:

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

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

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

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*.

Variable	**Unit**	**Definition**
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.
RTDCEXP $_{q,\ p,\ i}$	MW	*Real-Time DC Export per QSE per Settlement Point*—The aggregated DC Tie Schedule through DC Tie *p* submitted by QSE *q* that is under the Oklaunion Exemption as an exporter from the ERCOT Region, for the 15-minute Settlement Interval *i*.
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
$\text{RUCCPADJ}_{q,\,h}$	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.
$\text{RUCCSADJ}_{q,\,h}$	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.
$\text{DAEP}_{q,\,p,\,h}$	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.
$\text{DAES}_{q,\,p,\,h}$	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.
$\text{RTQQEPSNAP}_{q,\,p,\,i}$	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.
$\text{RTQQESSNAP}_{q,\,p,\,i}$	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.
$\text{RTQQEPADJ}_{q,\,p,\,i}$	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.
$\text{RTQQESADJ}_{q,\,p,\,i}$	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, NPRR1032, NPRR1054, and NPRR1139: 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, NPRR1032, NPRR1054, or NPRR1139:]

5.7.4.1.1 Capacity Shortfall Ratio Share

(1) In calculating the shortfall amount for each QSE, the Resource capacity 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 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 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 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:

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

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

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

(9) 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) 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:

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

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

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

(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:

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

Where:

$$\text{ASCAP1SNAP}_{ruc,\,q,\,i} = \text{RUPOSSNAP}_{ruc,\,q,\,h} - \sum_{r} \text{ASOFR1SNAP}_{ruc,\,q,\,r,\,h}$$

$$\text{ASCAP2SNAP}_{ruc,\,q,\,i} = \text{RRPOSSNAP}_{ruc,\,q,\,h} - \sum_{r} \text{ASOFR2SNAP}_{ruc,\,q,\,r,\,h}$$

$$\text{ASCAP3SNAP}_{ruc,\,q,\,i} = (\text{RUPOSSNAP}_{ruc,\,q,\,h} + \text{RRPOSSNAP}_{ruc,\,q,\,h}) - \sum_{r} \text{ASOFR3SNAP}_{ruc,\,q,\,r,\,h}$$

$$\text{ASCAP4SNAP}_{ruc,\,q,\,i} = (\text{RUPOSSNAP}_{ruc,\,q,\,h} + \text{RRPOSSNAP}_{ruc,\,q,\,h} + \text{ECRPOSSNAP}_{ruc,\,q,\,h}) - \sum_{r} \text{ASOFR4SNAP}_{ruc,\,q,\,r,\,h}$$

$$\text{ASCAP5SNAP}_{ruc,\,q,\,i} = (\text{RUPOSSNAP}_{ruc,\,q,\,h} + \text{RRPOSSNAP}_{ruc,\,q,\,h} + \text{ECRPOSSNAP}_{ruc,\,q,\,h} + \text{NSPOSSNAP}_{ruc,\,q,\,h}) - \sum_{r} \text{ASOFR5SNAP}_{ruc,\,q,\,r,\,h}$$

$$\text{ASCAP6SNAP}_{ruc,\,q,\,i} = \text{RDPOSSNAP}_{ruc,\,q,\,h} - \sum_{r} \text{ASOFR6SNAP}_{ruc,\,q,\,r,\,h}$$

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

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

(13) 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:

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

Where:

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

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

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:

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

(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:

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

Where:

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

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

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

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

$$\text{ASCAP5ADJ}_{q,\,i} = (\text{RUPOSADJ}_{q,\,h} + \text{RRPOSADJ}_{q,\,h} + \text{ECRPOSADJ}_{q,\,h} + \text{NSPOSADJ}_{q,\,h}) - \sum_{r} \text{ASOFR5ADJ}_{q,\,r,\,h}$$

$$\text{ASCAP6ADJ}_{q,\,i} = \text{RDPOSADJ}_{q,\,h} - \sum_{r} \text{ASOFR6ADJ}_{q,\,r,\,h}$$

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* 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* 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* 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* 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* 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* 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*.
ASCAP1SNAP $_{ruc,\ q,\ i}$	MW	*Ancillary Service Net Capacity Level 1 at Snapshot* —The net capacity for Reg-Up for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
ASCAP2SNAP $_{ruc,\ q,\ i}$	MW	*Ancillary Service Net Capacity Level 2 at Snapshot* —The net capacity for RRS for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
ASCAP3SNAP $_{ruc,\ q,\ i}$	MW	*Ancillary Service Net Capacity Level 3 at Snapshot* —The net capacity for Reg-Up and RRS for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
ASCAP4SNAP $_{ruc,\ q,\ i}$	MW	*Ancillary Service Net Capacity Level 4 at Snapshot* —The net capacity for Reg-Up, RRS, and ECRS for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
ASCAP5SNAP $_{ruc,\ q,\ i}$	MW	*Ancillary Service Net Capacity Level 5 at Snapshot* —The net capacity for Reg-Up, RRS, ECRS, and Non-Spinning Reserve (Non-Spin) for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
ASCAP6SNAP $_{ruc,\ q,\ i}$	MW	*Ancillary Service Net Capacity Level 6 at Snapshot* —The net capacity for Reg-Down for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.

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

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

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

$\text{ASOFR3ADJ}_{q,\,r,\,h}$	MW	*Ancillary Service Offer Level 3 at End of Adjustment Period* – The capacity represented by validated Reg-Up and RRS Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.
$\text{ASOFR4ADJ}_{q,\,r,\,h}$	MW	*Ancillary Service Offer Level 4 at End of Adjustment Period* – The capacity represented by validated Reg-Up, RRS, and ECRS Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.
$\text{ASOFR5ADJ}_{q,\,r,\,h}$	MW	*Ancillary Service Offer Level 5 at End of Adjustment Period*– The capacity represented by validated Reg-Up, RRS, ECRS, and Non-Spin Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.
$\text{ASOFR6ADJ}_{q,\,r,\,h}$	MW	*Ancillary Service Offer Level 6 at End of Adjustment Period* – The capacity represented by validated Reg-Down Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.
$\text{RTAML}_{q,\,p,\,i}$	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*.
$\text{RUCCAPSNAP}_{ruc,\,q,\,i}$	MW	*RUC Capacity Snapshot at time of RUC*—The amount of the QSE *q*'s calculated capacity in the RUC Snapshot for the RUC process *ruc* for a 15-minute Settlement Interval *i*.
$\text{RCAPSNAP}_{ruc,\,q,\,r,\,h}$	MW	*Resource Capacity at Snapshot*—The available capacity of Generation Resource or ESR *r* represented by the QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. For ESRs and Generation Resources that are not IRRs, the available capacity shall be equal to HSL. For WGRs and PVGRs, the available capacity shall be equal to the WGRPP and the PVGRPP, respectively. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{DCIMPSNAP}_{ruc,\,q,\,p,\,i}$	MW	*DC Import at Snapshot*—The approved aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.

$\text{RTDCIMP}_{q, p}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated final, approved DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval.
$\text{RUCCPSNAP}_{ruc, q, h}$	MW	*RUC Capacity Purchase at Snapshot*—The QSE *q*'s capacity purchase, according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
$\text{RUCCSSNAP}_{ruc, q, h}$	MW	*RUC Capacity Sale at Snapshot*—The QSE *q*'s capacity sale, according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
$\text{RUCCAPADJ}_{q, i}$	MW	*RUC Capacity at End of Adjustment Period*—The amount of the QSE *q*'s calculated capacity, excluding capacity for IRRs, at the end of the Adjustment Period for a 15-minute Settlement Interval *i.*
$\text{RCAPADJ}_{q, r, h}$	MW	*Resource Capacity at End of Adjustment Period*—The HSL of a non-IRR Generation Resource or ESR *r* represented by the QSE *q* at the end of the Adjustment Period, for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RUCCPADJ}_{q, h}$	MW	*RUC Capacity Purchase at End of Adjustment Period*—The QSE *q*'s capacity purchase, at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
$\text{RUCCSADJ}_{q, h}$	MW	*RUC Capacity Sale at End of Adjustment Period*—The QSE *q*'s capacity sale, at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
$\text{DAEP}_{q, p, h}$	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.
$\text{DAES}_{q, p, h}$	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.
$\text{RTQQEPSNAP}_{ruc, q, p, i}$	MW	*Real-Time QSE-to-QSE Energy Purchase at Snapshot*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the RUC Snapshot for the RUC process *ruc*.
$\text{RTQQESSNAP}_{ruc, q, p, i}$	MW	*Real-Time QSE-to-QSE Energy Sale at Snapshot*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the RUC Snapshot for the RUC process *ruc*.
$\text{RTQQEPADJ}_{q, p, i}$	MW	*Real-Time QSE-to-QSE Energy Purchase at End of Adjustment Period*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, at the end of the Adjustment Period for that Settlement Interval.
$\text{RTQQESADJ}_{q, p, i}$	MW	*Real-Time QSE-to-QSE Energy Sale at End of Adjustment Period*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, at the end of the Adjustment Period for that Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource, an ESR, or a Load Resource.
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.

5.7.4.1.2 RUC Capacity Credit

(1) A QSE that is charged for a capacity shortfall in one RUC process gets a capacity credit equal to the minimum of the QSE's RUC shortfall (MW) or the total RUC capacity purchased multiplied by the QSE's shortfall ratio share. The capacity credit to be used in future RUC processes for the same 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RUCCAPCREDIT}_{ruc,i,q} = \mathbf{Min\ [RUCSF}_{ruc,i,q}\mathbf{,\ (RUCCAPTOT}_{ruc,h}\mathbf{*\ RUCSFRS}_{ruc,i,q}\mathbf{)]}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{RUCCAPCREDIT}_{ruc,i,q}$	MW	*RUC Capacity Credit by QSE*—The capacity credit resulting from capacity paid through the RUC Capacity-Short Charge for the 15-minute Settlement Interval.
$\text{RUCSF}_{ruc,i,q}$	MW	*RUC Shortfall*—The QSE's capacity shortfall for the RUC process for the 15-minute Settlement Interval.
$\text{RUCSFRS}_{ruc,i,q}$	none	*RUC Shortfall Ratio Share*—The ratio of the QSE's capacity shortfall to the sum of all QSEs' capacity shortfalls, for the RUC process, for the 15-minute Settlement Interval.
$\text{RUCCAPTOT}_{ruc,h}$	MW	*RUC Capacity Total*—The total capacity of all RUC-committed Resources during the RUC process, for the hour that includes the 15-minute Settlement Interval.
q	none	A QSE.
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 Capacity Credit is calculated.

5.7.4.2 RUC Make-Whole Uplift Charge

(1) If the revenues from the charges under Section 5.7.4.1, RUC Capacity-Short Charge, are not enough to cover all RUC Make-Whole Payments, including amounts for RMR Units, for a 15-minute Settlement Interval, then the difference will be uplifted to all QSEs on a Load Ratio Share basis, as a RUC Make-Whole Uplift Charge, calculated as follows:

$$\mathbf{LARUCAMT}_{q,i} = \mathbf{(-1) * (\ RUCMWAMTTOT}_{h}\mathbf{\ /\ 4 + RUCCSAMTTOT}_{i}\mathbf{) * LRS}_{q,i}$$

Where:

$$\text{RUCMWAMTTOT}_{h} = \sum_{ruc} \text{RUCMWAMTRUCTOT}_{ruc,h}$$

$$\text{RUCCSAMTTOT}_{i} = \sum_{ruc} \sum_{q} \text{RUCCSAMT}_{ruc,i,q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{LARUCAMT}_{q,i}$	$	*RUC Make-Whole Uplift Charge*—The amount owed from the QSE based on Load Ratio Share, for the 15-minute Settlement Interval.
RUCMWAMTTOT_{h}	$	*RUC Make-Whole Amount Total*—The sum of RUC Make-Whole Payments for all RUC processes, including amounts for RMR Units, for the hour that includes the 15-minute Settlement Interval.
$\text{RUCMWAMTRUCTOT}_{ruc,h}$	$	*RUC Make-Whole Amount Total per RUC*—The sum of RUC Make-Whole Payments for a particular RUC process, including payments for RMR Units, for the hour that includes the 15-minute Settlement Interval.
RUCCSAMTTOT_{i}	$	*RUC Capacity Amount Total*—The sum of RUC Capacity-Short Charges for all QSEs and RUC processes, including payments for RMR Units, for the 15-minute Settlement Interval.
$\text{RUCCSAMT}_{ruc,i,q}$	$	*RUC Capacity-Short Amount*—The charge to a QSE, due to capacity shortfall for a particular RUC process, for the 15-minute Settlement Interval.
$\text{LRS}_{q,i}$	none	*Load Ratio Share*—The ratio of Adjusted Metered Load to the total ERCOT Adjusted Metered Load for the 15-minute Settlement Interval. See Section 6.6.2, Load Ratio Share, item (2).
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
ruc	none	A RUC Process.
q	none	A QSE.

5.7.5 RUC Clawback Payment

(1) ERCOT shall pay the revenues from all RUC Clawback Charges, including amounts for RMR Units, in a 15-minute Settlement Interval to all QSEs, on an LRS basis, as the RUC Clawback Payment. The RUC Clawback Payment is calculated as follows for each QSE for each 15-minute Settlement Interval:

$$\mathbf{LARUCCBAMT}_{q,i} = \mathbf{(-1) * (RUCCBAMTTOT}_{h} \mathbf{/ 4 * LRS}_{q,i}\mathbf{)}$$

Where:

$$\text{RUCCBAMTTOT}_{h} = \sum_{q} \sum_{r} \text{RUCCBAMT}_{q,r,h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LARUCCBAMT_{q,i}$	$	*RUC Clawback Payment*—The RUC make-whole clawback payment to a QSE to uplift RUC Make-Whole Clawback Charges received, for a 15-minute Settlement Interval.
$RUCCBAMTTOT_{h}$	$	*RUC Clawback Charge Total* —The sum of RUC Clawback Charges to all QSEs, including amounts for RMR Units, for the hour that includes the 15-minute Settlement Interval.
$LRS_{q,i}$	none	*Load Ratio Share*—The LRS for the 15-minute Settlement Interval. See Section 6.6.2, Load Ratio Share.
$RUCCBAMT_{q,r,h}$	$	*RUC Clawback Charge*—The RUC Clawback Charge to the QSE *q* for the Resource *r*, for the hour that includes the 15-minute Settlement Interval. When one or more Combined Cycle Generation Resources are committed by RUC, a charge is made to the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
q	None	A QSE.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
r	none	A RUC-committed Generation Resource.

5.7.6 RUC Decommitment Charge

(1) ERCOT shall charge each QSE a RUC Decommitment Charge, on an LRS basis, all revenues paid as a result of RUC Decommitment Payments, including amounts for RMR Units. The RUC Decommitment Charge for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LARUCDCAMT_{q,i} = (-1) * [(RUCDCAMTTOT_{h} / 4) * LRS_{q,i}]}$$

Where:

$$RUCDCAMTTOT_{h} = \sum_{q} \sum_{r} RUCDCAMT_{q,r,h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LARUCDCAMT_{q,i}$	$	*RUC Decommitment Charge*—The RUC Decommitment Charge to a QSE, for a 15-minute Settlement Interval.
$RUCDCAMTTOT_{h}$	$	*RUC Decommitment Charge Total*—The sum of RUC Decommitment Payments to all QSEs, including amounts for RMR Units, for the hour that includes the 15-minute Settlement Interval.
$LRS_{q,i}$	none	*Load Ratio Share*—The LRS for the 15-minute Settlement Interval. See Section 6.6.2, Load Ratio Share.
$RUCDCAMT_{q,r,h}$	$	*RUC Decommitment Charge*—The RUC Decommitment Charge to the QSE *q* for the Resource *r*, for the hour that includes the 15-minute Settlement Interval. When one or more Combined Cycle Generation Resources are decommitted by RUC, payment is made to the Combined Cycle Train for all RUC-decommitted Combined Cycle Generation Resources.

Variable	Unit	Definition
q	None	A QSE.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
r	None	A RUC-decommitted Generation Resource.

5.7.7 Settlement of Switchable Generation Resources (SWGRs) Operating in a Non-ERCOT Control Area

(1) A QSE representing an SWGR operating in ERCOT due to a RUC instruction for an actual or anticipated EEA condition with a status of ONRUC is not eligible for RUC Settlement as described in Section 5.7.1, RUC Make-Whole Payment, and Section 5.7.2, RUC Clawback Charge, but may obtain compensation by submitting a Settlement and billing dispute pursuant to Section 6.6.12, Make-Whole Payment for Switchable Generation Resources Committed for Energy Emergency Alert (EEA).

5.8 Annual RUC Reporting Requirement

(1) ERCOT shall report to the Technical Advisory Committee (TAC), each January, an assessment of market impacts and Settlements for the aggregate Reliability Unit Commitment (RUC) activity, delineated by type of RUC instruction as follows:

(a) RUC instructions issued for Ancillary Service shortages (failure to sufficiently procure one or more Ancillary Service markets in the Day-Ahead Market (DAM) or subsequent Supplemental Ancillary Service Markets (SASMs));

[NPRR1009: Delete paragraph (a) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(b) RUC instructions issued for irresolvable transmission system constraints;

(c) RUC instructions issued in anticipation of extreme cold weather/startup failures;

(d) RUC instructions issued for capacity;

(e) RUC instructions issued for system inertia;

(f) RUC instructions issued to Resources receiving an Outage Schedule Adjustment (OSA); and

(g) A summary of RUC Settlements;

(i) RUC charges associated with RUC Make-Whole Amount Total per RUC, as defined in Section 5.7.4.1, RUC Capacity-Short Charge; and

(ii) RUC Shortfall Total, as defined in Section 5.7.4.1.1, Capacity Shortfall Ratio Share.

ERCOT Nodal Protocols

Section 6: Adjustment Period and Real-Time Operations

December 1, 2022

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6 ADJUSTMENT PERIOD AND REAL-TIME OPERATIONS

6.1 Introduction

(1) This Section addresses the following components: the Adjustment Period and Real-Time Operations, including Emergency Operations.

(2) The Adjustment Period provides each Qualified Scheduling Entity (QSE) the opportunity to adjust its trades, Self-Schedules, and Resource commitments as more accurate information becomes available under Section 6.4, Adjustment Period. During the Adjustment Period, ERCOT continues to evaluate system sufficiency and security by use of Hour-Ahead Reliability Unit Commitment (RUC) processes, as described in Section 5, Transmission Security Analysis and Reliability Unit Commitment. Under certain conditions during the Adjustment Period, ERCOT may also open one or more Supplemental Ancillary Service Markets (SASMs), as described in Section 6.4.9.2, Supplemental Ancillary Services Market.

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

(2) The Adjustment Period provides each Qualified Scheduling Entity (QSE) the opportunity to adjust its trades, Self-Schedules, and Resource commitments as more accurate information becomes available under Section 6.4, Adjustment Period. During the Adjustment Period, ERCOT continues to evaluate system sufficiency and security by use of Hour-Ahead Reliability Unit Commitment (RUC) processes, as described in Section 5, Transmission Security Analysis and Reliability Unit Commitment.

(3) During Real-Time operations, ERCOT dispatches Resources under normal system conditions and behavior based on economics and reliability to match system Load with On-Line generation while observing Resource and transmission constraints. The Security-Constrained Economic Dispatch (SCED) process produces Base Points for Resources. ERCOT uses the Base Points from the SCED process and uses the deployment of Regulation Up (Reg-Up), Regulation Down (Reg-Down), Responsive Reserve (RRS), and Non-Spinning Reserve (Non-Spin) to control frequency and solve potential reliability issues.

[NPRR863 and NPRR1010: Replace applicable portions of paragraph (3) above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(3) During Real-Time operations, ERCOT dispatches Resources under normal system conditions and behavior based on economics and reliability to match system Load with On-Line generation while observing Resource and transmission constraints. The Security-Constrained Economic Dispatch (SCED) process produces Base Points and Ancillary Service awards for Resources. ERCOT uses the Base Points from the SCED

process and uses the deployment of Regulation Up (Reg-Up), Regulation Down (Reg-Down), ERCOT Contingency Reserve Service (ECRS), Responsive Reserve (RRS), and Non-Spinning Reserve (Non-Spin) to control frequency and solve potential reliability issues.

(4) Real-Time energy settlements use Real-Time Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a 15-minute Settlement Interval, using the Locational Marginal Prices (LMPs) from all of the executions of SCED in the Settlement Interval. In contrast, the Day-Ahead Market (DAM) energy settlements will use DAM Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a one-hour Settlement Interval.

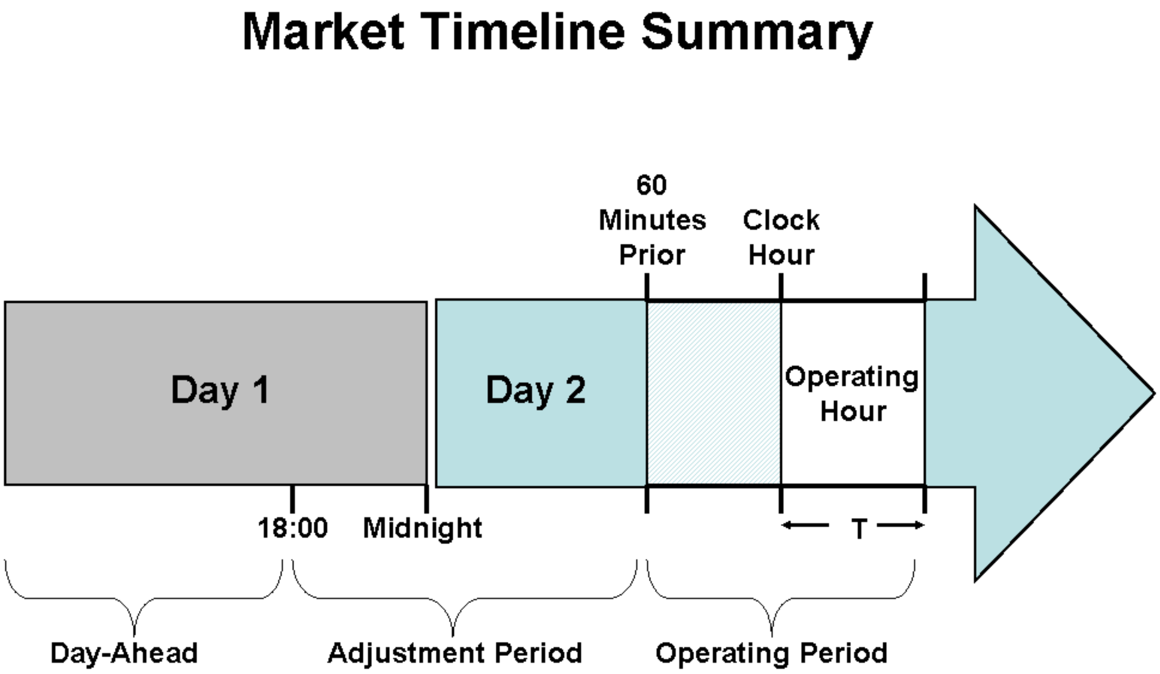
[NPRR1010: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) Real-Time energy settlements use Real-Time Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a 15-minute Settlement Interval, using the Locational Marginal Prices (LMPs) from all of the executions of SCED in the Settlement Interval. Similarly, Real-Time Ancillary Service Settlements use Real-Time Market Clearing Prices for Capacity (MCPCs) for a 15-minute Settlement Interval, using the MCPCs from all of the executions of SCED in the Settlement Interval. In contrast, the Day-Ahead Market (DAM) energy settlements will use DAM Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a one-hour Settlement Interval, and DAM Ancillary Service Settlements will use DAM MCPCs for a one-hour Settlement Interval.

(5) To the extent that the ERCOT CEO or designee determines that Market Participant activities have produced an outcome inconsistent with the efficient operation of the ERCOT-administered markets as defined in subsection (c)(2) of P.U.C. SUBST. R. 25.503, Oversight of Wholesale Market Participants, ERCOT may prohibit the activity by Notice for a period beginning on the date of the Notice and ending no later than 45 days after the date of the Notice. ERCOT may issue subsequent Notices on the same activity. The ERCOT CEO may deem any Nodal Protocol Revision Request (NPRR) designed to correct the activity or issues affecting the activity as Urgent pursuant to Section 21.5, Urgent and Board Priority Nodal Protocol Revision Requests and System Change Requests.

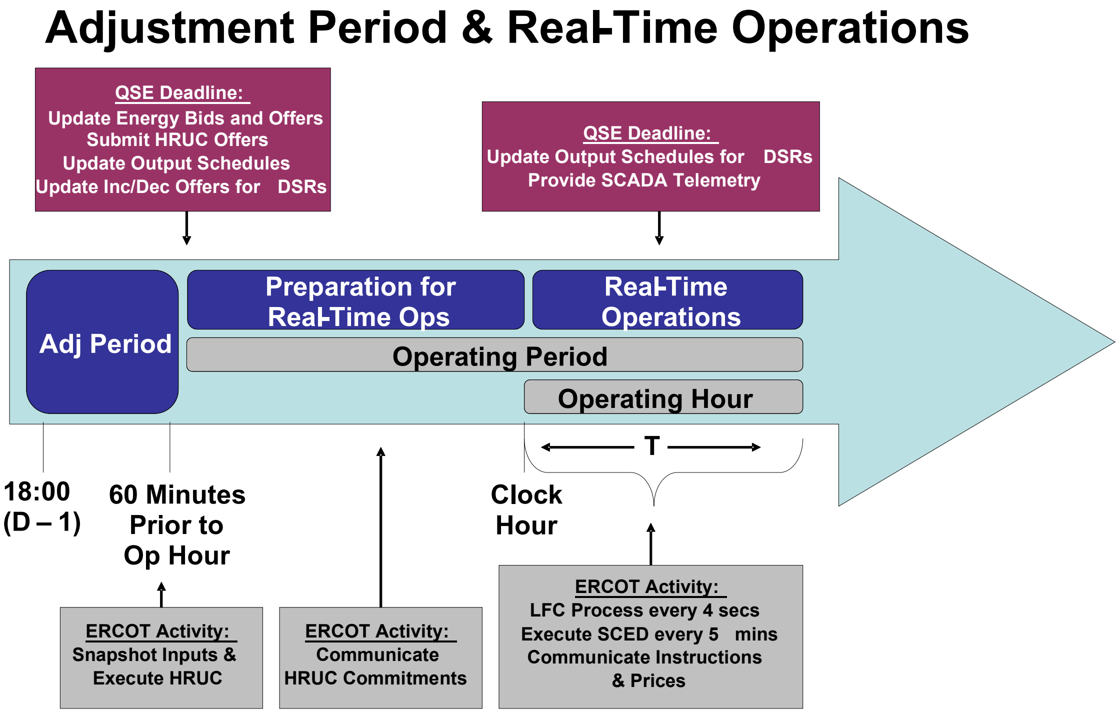
6.2 Market Timeline Summary

(1) The figure below is a high-level summary of the overall market timeline:


Market Timeline Summary

6.3 Adjustment Period and Real-Time Operations Timeline

(1) The figure below highlights the major activities that occur in the Adjustment Period and Real-Time operations:


Adjustment Period & Real-Time Operations

(2) Activities for the Adjustment Period begin at 1800 in the Day-Ahead and end one full hour before the start of the Operating Hour. The figure above is intended to be only a general guide and not controlling language, and any conflict between this figure and another section of the Protocols is controlled by the other section.

(3) ERCOT shall monitor Real-Time Locational Marginal Prices (LMPs), Supplemental Ancillary Services Market (SASM) Market Clearing Prices for Capacity (MCPCs), and Real-Time Settlement Point Prices, including Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Off-Line Reserve Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Reserve Prices for On-Line Reserves and Real-Time Reserve Prices for Off-Line Reserves, for errors and if there are conditions that cause the price to be questionable, ERCOT shall notify all Market Participants that the Real-Time LMPs, SASM MCPCs, and Real-Time Settlement Point Prices are under investigation as soon as practicable.

(4) ERCOT shall correct prices for an Operating Day when accurate prices can be determined, the impact of the price correction is determined to be significant, and one of the following conditions has been met: a market solution is determined to be invalid, invalid prices are identified in an otherwise valid market solution, the Base Points received by Market Participants are inconsistent with the Base Points of a valid market solution, or the Security-Constrained Economic Dispatch (SCED) process experiences a failure as described in Section 6.5.9.2, Failure of the SCED Process. The following are some reasons that may cause these conditions:

(a) Data Input error: Missing, incomplete, stale, or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices.

(b) Data Output error: These include: incorrect or incomplete data transfer, price recalculation error in post-processing, and Base Points inconsistent with prices due to the Emergency Base Point flag remaining activated even when the SCED solution is valid.

(c) Hardware/Software error: These include unpredicted hardware or software failures, planned market system or database outages, planned application or database upgrades, software implementation errors, and failure of the market run to complete.

(d) Inconsistency with the Protocols or Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.

(5) For purposes of a price correction performed prior to 1600 on the second Business Day after the Operating Day, the impact of a price correction shall be considered significant, as that term is used in paragraph (4) above, for the Operating Day when:

(a) The absolute value change to any single Real-Time Settlement Point Price at a Resource Node is greater than $0.05/MWh;

(b) The price correction would require ERCOT to change more than 50 Real-Time Settlement Point Prices;

(c) The absolute value change to any Real-Time Settlement Point Price at a Load Zone or Hub is greater than $0.02/MWh;

(d) The estimated absolute total dollar impact for changes to Real-Time prices for energy metered is greater than $500; or

(e) The absolute total dollar impact for changes to SASM MCPCs is greater than $500.

(6) If it is determined that any Real-Time Settlement Point Prices, Settlement Point LMPs, Electrical Bus LMPs, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, and/or constraint Shadow Prices are erroneous, ERCOT shall correct the prices before the prices are considered final in paragraph (7) below. Specifically:

(a) If it is determined that correcting the Real-Time Settlement Point Prices will not affect the Base Points that were received by Qualified Scheduling Entities (QSEs), then ERCOT shall correct the prices before the prices are considered final in paragraph (7) below.

(b) If it is determined that correcting the Real-Time Settlement Point Prices will affect the Base Points that were received by QSEs, then ERCOT shall correct the prices before the prices are considered final and settle the SCED executions as failed in accordance with Section 6.5.9.2.

(c) If the Base Points received by QSEs are inconsistent with the Real-Time Settlement Point Prices reduced by the sum of the Real-Time On-Line Reliability Deployment Prices and the Real-Time Reserve Prices for On-Line Reserves averaged over the 15-minute Settlement Interval, then ERCOT shall consider those Base Points as due to manual override from the ERCOT Operator and settle the relevant Settlement Interval(s) in accordance with Section 6.6.9, Emergency Operations Settlement.

(7) All Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs are final at 1600 of the second Business Day after the Operating Day.

(a) However, after Real-Time LMPs, Real Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs are final, if ERCOT determines that prices qualify for a price correction pursuant to paragraph (4) above and that ERCOT will seek ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT's duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT's authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT's authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

(b) Before seeking ERCOT Board review of prices, ERCOT will determine if the impact of the price correction is significant, as that term is used in paragraph (4) above, by calculating the potential changes to the Real-Time Market (RTM) Settlement Statement(s) of any Counter-Party on a given Operating Day. ERCOT shall seek ERCOT Board review of prices if the change in RTM Settlement Statement(s) would result in the absolute value impact to any single Counter-Party, based on the sum of all original RTM Settlement Statement amounts of Market Participants assigned to the Counter-Party, to be greater than:

(i) 2% and also greater than $20,000; or

(ii) 20% and also greater than $2,000.

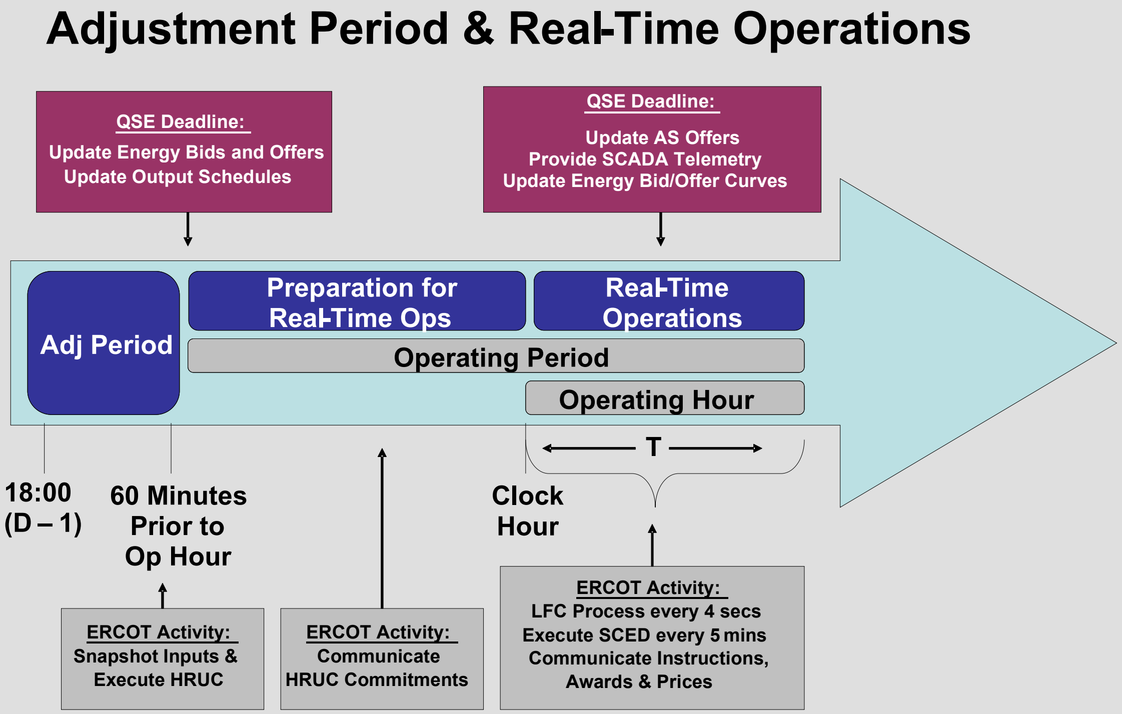
(c) The ERCOT Board may review and change Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices should be corrected for an Operating Day.

(d) In review of Real-Time LMPs, Real Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices should be corrected for an Operating Day.

[NPRR1000, NPRR1010, and NPRR1014: Replace applicable portions of Section 6.3 above with the following upon system implementation for NPRR1000 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.3 Adjustment Period and Real-Time Operations Timeline

(1) The figure below highlights the major activities that occur in the Adjustment Period and Real-Time operations:



(2) Activities for the Adjustment Period begin at 1800 in the Day-Ahead and end one full hour before the start of the Operating Hour. The figure above is intended to be only a general guide and not controlling language, and any conflict between this figure and another section of the Protocols is controlled by the other section.

(3) ERCOT shall monitor Real-Time Locational Marginal Prices (LMPs), Real-Time Market Clearing Prices for Capacity (MCPCs), and Real-Time Settlement Point Prices, including Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, for errors and if there are conditions that cause the price to be questionable, as soon as practicable, ERCOT shall notify all Market Participants that the Real-Time LMPs, Real-Time MCPCs, and Real-Time Settlement Point Prices are under investigation.

(4) ERCOT shall correct prices for an Operating Day when accurate prices can be determined, the impact of the price correction is determined to be significant, and one of the following conditions has been met: a market solution is determined to be invalid, invalid prices are identified in an otherwise valid market solution, the Base Points or Ancillary Service awards received by Market Participants are inconsistent with the Base Points or Ancillary Service awards of a valid market solution, or the Security-Constrained Economic Dispatch (SCED) process experiences a failure as described in Section 6.5.9.2, Failure of the SCED Process. The following are some reasons that may cause these conditions.

(a) Data Input error: Missing, incomplete, stale, or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices.

(b) Data Output error: These include: incorrect or incomplete data transfer, price recalculation error in post-processing, and Base Points inconsistent with prices due to the Emergency Base Point flag remaining activated even when the SCED solution is valid.

(c) Hardware/Software error: These include unpredicted hardware or software failures, planned market system or database outages, planned application or database upgrades, software implementation errors, and failure of the market run to complete.

(d) Inconsistency with the Protocols or Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.

(5) For purposes of a price correction performed prior to 1600 on the second Business Day after the Operating Day, the impact of a price correction shall be considered significant, as that term is used in paragraph (4) above, for the Operating Day when:

(a) The absolute value change to any single Real-Time Settlement Point Price at a Resource Node is greater than $0.05/MWh;

(b) The price correction would require ERCOT to change more than 50 Real-Time Settlement Point Prices;

(c) The absolute value change to any Real-Time Settlement Point Price at a Load Zone or Hub is greater than $0.02/MWh;

(d) The estimated absolute total dollar impact for changes to Real-Time prices for energy metered is greater than $500; or

(e) The absolute total dollar impact for changes to SASM MCPCs is greater than $500.

(6) If it is determined that any Real-Time Settlement Point Prices, Settlement Point LMPs, Electrical Bus LMPs, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Ancillary Service, and/or constraint Shadow Prices are erroneous, ERCOT shall correct the prices before the prices are considered final in paragraph (7) below. Specifically:

(a) If it is determined that correcting the Real-Time Settlement Point Prices will not affect the Base Points, and correcting Real-Time MCPCs will not affect Ancillary Service awards, then ERCOT shall correct the prices before the prices are considered final in paragraph (7) below.

(b) If it is determined that correcting the Real-Time Settlement Point Prices will affect the Base Points, or correcting Real-Time MCPCs will affect Ancillary Service awards, then ERCOT shall correct the prices before the prices are considered final and settle the SCED executions as failed in accordance with Section 6.5.9.2.

(c) For Settlement purposes, if the Base Points are inconsistent with the Real-Time Settlement Point Prices, reduced by the Real-Time Reliability Deployment Price Adder for Energy, or Ancillary Service awards are inconsistent with the Real-Time MCPCs, reduced by the Real-Time Reliability Deployment Price Adder for Ancillary Service, averaged over the 15-minute Settlement Interval, then ERCOT shall consider the relevant Settlement Interval(s) in accordance with Section 6.6.9, Emergency Operations Settlement.

(7) All Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service are final at 1600 of the second Business Day after the Operating Day.

(a) However, after Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service are final, if ERCOT determines that prices qualify for a price correction pursuant to paragraph (4) above and that ERCOT will seek ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT's duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT's authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT's authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

(b) Before seeking ERCOT Board review of prices, ERCOT will determine if the impact of the price correction is significant, as that term is used in paragraph (4) above, by calculating the potential changes to the RTM Settlement Statement(s) of any Counter-Party on a given Operating Day. ERCOT shall seek ERCOT Board review of prices if the change in RTM Settlement Statement(s) would result in the absolute value impact to any single Counter-Party, based on the sum of all original RTM Settlement Statement amounts of Market Participants assigned to the Counter-Party, to be greater than:

(i) 2% and also greater than $20,000; or

(ii) 20% and also greater than $2,000.

(c) The ERCOT Board may review and change Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices should be corrected for an Operating Day.

(d) In review of Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices should be corrected for an Operating Day.

6.3.1 Activities for the Adjustment Period

(1) The following table summarizes the timeline for the Adjustment Period and the activities of QSEs and ERCOT. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Adjustment Period	**QSE Activities**	**ERCOT Activities**
Time = From 1800 in the Day-Ahead up to one hour before the start of the Operating Hour	Submit and update Energy Trades, Capacity Trades, Self-Schedules, and Ancillary Service Trades Submit and update Output Schedules Submit and update Incremental and Decremental Energy Offer Curves for Dynamically Scheduled Resources (DSRs) ***[NPRR1000: Delete the item above upon system implementation.]*** Submit and update Energy Offer Curves and/or RTM Energy Bids ***[NPRR1014: Insert the item below upon system implementation:]*** Submit Energy Bid/Offer Curves for Energy Storage Resources (ESRs) Update Current Operating Plan (COP) Request Resource decommitments Submit Three-Part Supply Offers for Off-Line Generation Resources Submit offers for any Supplemental Ancillary Service Markets ***[NPRR1010 and NPRR1014: Replace applicable portions of the item above with the***	Post shift schedules on the Market Information System (MIS) Secure Area Validate Energy Trades, Capacity Trades, Self-Schedules, and Ancillary Service Trades and identify invalid or mismatched trades Validate Output Schedules Validate Incremental and Decremental Energy Offer Curves Validate Energy Offer Curves and/or RTM Energy Bids ***[NPRR1014: Insert the item below upon system implementation:]*** Validate Energy Bid/Offer Curves Validate COP including validation of the deliverability of Ancillary Services from Resources for the next Operating Period Review and approve or reject Resource decommitments Validate Three-Part Supply Offers Publish Notice of Need to Procure Additional Ancillary Service capacity if required ***[NPRR1010 and NPRR1014: Replace applicable portions of the item above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or***

Adjustment Period	**QSE Activities**	**ERCOT Activities**
	following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:] Submit and update Ancillary Service Offers Communicate Resource Forced Outages	***upon system implementation for NPRR1014:]*** Publish Notice of need to update the Ancillary Service Plan if required and update the Ancillary Service Demand Curves (ASDCs) for the affected hours and Ancillary Services Validate Ancillary Service Offers At the end of the Adjustment Period snap-shot the net capacity credits for Hourly Reliability Unit Commitment (HRUC) Settlement Update Short-Term Wind Power Forecast (STWPF) Update Short-Term PhotoVoltaic Power Forecast (STPPF) Execute the Hour-Ahead Sequence Notify the QSE via the MIS Certified Area that an Energy Offer Curve, RTM Energy Bid or Output Schedule has not yet been submitted for a Resource as a reminder that one of the three must be submitted by the end of the Adjustment Period ***[NPRR1010 and NPRR1014: Insert applicable portions of the items below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]*** Notify the QSE via the MIS Certified Area that an Ancillary Service Offer has not yet been submitted for a Resource by the end of the Adjustment Period Notify the QSE via the MIS Certified Area that an Energy Bid/Offer Curve has not yet been submitted for an ESR by the end of the Adjustment Period

6.3.2 *Activities for Real-Time Operations*

(1) Activities for Real-Time operations begin at the end of the Adjustment Period and conclude at the close of the Operating Hour.

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	**QSE Activities**	**ERCOT Activities**
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
Before the start of each SCED run	Update Output Schedules for DSRs	Validate Output Schedules for DSRs Execute Real-Time Sequence
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy prices
During the Operating Hour	Telemeter the Ancillary Service Resource Responsibility for each Resource Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP with actual Resource Status and limits and Ancillary Service Schedules Communicate Resource Forced Outages to ERCOT	Communicate all binding Base Points, Dispatch Instructions, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves, and Real-Time Reserve Price Adders for Off-Line Reserves and LMPs for energy and Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total Block

Operating Period	QSE Activities	ERCOT Activities
	Communicate to ERCOT Resource changes to Ancillary Service Resource Responsibility via telemetry in the time window beginning 30 seconds prior to the five-minute clock interval and ending ten seconds prior to that five-minute clock interval	Load Transfer (BLT) MW that is added to or subtracted from the Demand, total Low Ancillary Service Limit (LASL), total High Ancillary Service Limit (HASL), Real-Time On-Line Reliability Deployment Price Adder using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs) Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves and Real-Time Reserve Price Adders for Off-Line Reserves, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total On-Line LASL, total On-Line HASL, Real-Time On-Line Reliability Deployment Price Adder created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generator (SOTGs). These prices shall

Operating Period	QSE Activities	ERCOT Activities
		include all Real-Time Reserve Price Adders for On-Line Reserves and Real-Time On-Line Reliability Deployment Price Adders created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective Post on the ERCOT website the projected non-binding LMPs created by each SCED process for each Resource Node, the projected total Real-Time reserve amount for On-Line reserves and Off-Line reserves, the projected Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders, and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, total LASL, total HASL, Real-Time On-Line Reliability Deployment Price Adder and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by

Operating Period	QSE Activities	ERCOT Activities
		Transmission Element name (contingency /overloaded element pairs) Post on the ERCOT website the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG and SOTG immediately following the end of each Settlement Interval Post the Real-Time On-Line Reliability Deployment Price, Real-Time Reserve Price for On-Line Reserves and the Real-Time Reserve Price for Off-Line Reserves immediately following the end of each Settlement Interval Post parameters as required by Section 6.4.9, Ancillary Services Capacity During the Adjustment Period and in Real-Time, on the ERCOT website

[NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1010, NPRR1058, and NPRR1077: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1058, or NPRR1077; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources

SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy and Ancillary Service prices
During the Operating Hour	Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP and telemetry with actual Resource Status and limits and Ancillary Service capabilities Submit and update Ancillary Service Offers Communicate Resource Forced Outages to ERCOT Submit and update Energy Offer Curves and/or RTM Energy Bids	Communicate all binding Base Points, Updated Desired Set Points (UDSPs), Ancillary Service awards, Dispatch Instructions, LMPs for energy, Real-Time MCPCs for Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Transmission and/or Distribution Service Provider (TDSP) standard offer Load management MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs). In communicating Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and Real-Time MCPCs for each Ancillary Service, and for the pricing run as described

		in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points and Ancillary Service awards from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs), Settlement Only Distribution Energy Storage Systems (SODESSs), Settlement Only Transmission Generators (SOTGs), and Settlement Only Transmission Energy Storage Systems (SOTESSs). These prices shall include Real-Time Reliability Deployment Price Adders for Energy created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective Post every 15 minutes on the ERCOT website the aggregate net injection from Settlement Only Generators (SOGs) and Settlement Only Energy Storage Systems (SOESSs) Post on the ERCOT website the projected non-binding LMPs for each Resource Node and Real-Time MCPCs for each Ancillary Service created by each SCED process and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to

		Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, Real-Time Reliability Deployment Price Adder for Energy, Real-Time On-Line Reliability Deployment Price Adders for Ancillary Service, and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points and Ancillary Service awards for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections. In posting Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) Post on the ERCOT website, the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG, SODESS, SOTG, and SOTESS immediately following the end of each Settlement Interval By Settlement Interval, post the 15-minute Real-Time Reliability Deployment Price for Energy, and the 15-minute Real-Time Reliability Deployment Price for Ancillary Service for each of the Ancillary Services

(3) At the beginning of each hour, ERCOT shall post on the ERCOT website the following information:

(a) Changes in ERCOT System conditions that could affect the security and dynamic transmission limits of the ERCOT System, including:

(i) Changes or expected changes, in the status of Transmission Facilities as recorded in the Outage Scheduler for the remaining hours of the current Operating Day and all hours of the next Operating Day; and

(ii) Any conditions such as adverse weather conditions as determined from the ERCOT-designated weather service;

(b) Updated system-wide Mid-Term Load Forecasts (MTLFs) for all forecast models available to ERCOT Operations, as well as an indicator for which forecast was in use by ERCOT at the time of publication;

(c) The quantities of RMR Services deployed by ERCOT for each previous hour of the current Operating Day; and

(d) Total ERCOT System Demand, from Real-Time operations, integrated over each Settlement Interval.

(4) No later than 0600, ERCOT shall post on the ERCOT website the actual system Load by Weather Zone, the actual system Load by Forecast Zone, and the actual system Load by Study Area for each hour of the previous Operating Day.

(5) ERCOT shall provide notification to the market and post on the ERCOT website Electrical Bus Load distribution factors and other information necessary to forecast Electrical Bus Loads. This report will be published when updates to the Load distribution factors are made. Private Use Network net Load will be redacted from this posting.

[NPRR1010: Insert paragraphs (6) and (7) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) After every SCED run, ERCOT shall post to the ERCOT website the total capability of Resources available to provide the following Ancillary Service combinations, based on the Resource telemetry from the QSE and capped by the limits of the Resource, for the most recent SCED execution:

(a) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;

(b) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;

(c) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;

(d) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;

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

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

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

(h) Capacity to provide Reg-Down.

(7) Each week, ERCOT shall post on the ERCOT website the historical SCED-interval data described in paragraph (6) above.

6.3.3 Real-Time Timeline Deviations

(1) ERCOT may temporarily deviate from the Real-Time deadlines but only to the extent necessary to ensure the secure operation of the ERCOT System. Temporary measures may include varying the timing requirements as specified below or omitting one or more procedures in the Real-Time Sequence. In such an event, ERCOT shall immediately issue a Watch and notify all QSEs of the following:

(a) Details of the affected timing requirements and procedures;

(b) Details of any interim requirements;

(c) An estimate of the period for which the interim requirements apply; and

(d) Reasons for the temporary variation.

6.3.4 ERCOT Notification of Validation Rules for Real-Time

(1) ERCOT shall provide each QSE with the information necessary to pre-validate its data for Real-Time operations, including publishing validation rules for offers, bids, and trades.

6.4 Adjustment Period

6.4.1 Capacity Trade, Energy Trade, Self-Schedule, and Ancillary Service Trades

(1) A detailed explanation of Capacity Trade criteria and validations performed by ERCOT is provided in Section 4.4.1, Capacity Trades. A Qualified Scheduling Entity (QSE) may submit and update Capacity Trades during the Adjustment Period.

(2) A detailed explanation of Energy Trade criteria and validations performed by ERCOT is provided in Section 4.4.2, Energy Trades. A QSE may submit and update Energy Trades during the Adjustment Period and through 1430 on the day following the Operating Day for Settlement.

(3) A detailed explanation of Self-Schedule criteria and validations performed by ERCOT is provided in Section 4.4.3, Self-Schedules. A QSE may submit and update Self-Schedules during the Adjustment Period.

(4) A detailed explanation of Ancillary Service Trade criteria and validations performed by ERCOT is provided in Section 4.4.7.3, Ancillary Service Trades. A QSE may submit and update Ancillary Service Trades during the Adjustment Period.

6.4.2 Output Schedules

(1) A QSE that represents a Resource, other than an RMR Unit, must submit and maintain either an Energy Offer Curve or an Output Schedule for the Resource for all times when the Resource is On-Line.

(2) The entry of an Energy Offer Curve for a Resource automatically nullifies the Output Schedule for that Resource and prohibits entry of future Output Schedules for that Resource for the time during which the Energy Offer Curve is in effect.

(3) For a Resource for which an Energy Offer Curve has not been submitted, the Security-Constrained Economic Dispatch (SCED) process uses the Output Schedule submitted for that Resource as desired Dispatch levels for the Resource.

[NPRR1014: Replace Section 6.4.2 above with the following upon system implementation:]

6.4.2 Output Schedules

(1) A QSE that represents a Resource, other than an RMR Unit, must submit and maintain an Energy Offer Curve, an Energy Bid/Offer Curve, or an Output Schedule for the Resource for all times when the Resource is On-Line.

(2) The entry of an Energy Offer Curve or Energy Bid/Offer Curve for a Resource automatically nullifies the Output Schedule for that Resource and prohibits entry of

future Output Schedules for that Resource for the time during which the Energy Offer Curve or Energy Bid/Offer Curve is in effect.

(3) For a Resource for which an Energy Offer Curve or Energy Bid/Offer Curve has not been submitted, the Security-Constrained Economic Dispatch (SCED) process uses the Output Schedule submitted for that Resource as desired Dispatch levels for the Resource.

6.4.2.1 Output Schedules for Resources Other than Dynamically Scheduled Resources

(1) An Output Schedule for a non-DSR Resource may be submitted and updated only during the Adjustment Period. An Output Schedule for a non-DSR Resource may be submitted and updated for each five-minute interval for each Operating Hour.

(2) For a Resource that is not a DSR and that is On-Line, the following provisions apply:

(a) The Output Schedule for a Qualifying Facility (QF) not submitting an Energy Offer Curve is considered to be equal to the telemetered output of the QF at the time that the SCED runs;

(b) The Output Schedule for Intermittent Renewable Resources (IRR) not submitting Energy Offer Curves is considered to be equal to the telemetered output of the Resource at the time that the SCED runs; and

(c) ERCOT shall create proxy Energy Offer Curves for the Resource under paragraph (4)(a) of Section 6.5.7.3, Security Constrained Economic Dispatch.

[NPRR1000 and NPRR1014: Replace applicable portions of Section 6.4.2.1 above with the following upon system implementation:]

6.4.2.1 Output Schedules for Resources

(1) An Output Schedule for a Resource may be submitted and updated only during the Adjustment Period. An Output Schedule for a Resource may be submitted and updated for each five-minute interval for each Operating Hour.

(2) For a Resource that is On-Line, the following provisions apply:

(a) The Output Schedule for a Qualifying Facility (QF) not submitting an Energy Offer Curve is considered to be equal to the telemetered output of the QF at the time that the SCED runs;

(b) The Output Schedule for Intermittent Renewable Resources (IRR) not submitting Energy Offer Curves is considered to be equal to the telemetered output of the Resource at the time that the SCED runs; and

(c) ERCOT shall create proxy Energy Offer Curves or proxy Energy Bid/Offer Curves for the Resource under paragraph (4)(a) of Section 6.5.7.3, Security Constrained Economic Dispatch.

6.4.2.2 Output Schedules for Dynamically Scheduled Resources

(1) A QSE representing a DSR may update the Output Schedule for a dispatch interval at any time before the SCED process for that interval.

(2) For a DSR that is On-Line, the following provisions apply:

(a) For an On-Line DSR for which its QSE has not submitted an Incremental and Decremental Energy Offer Curve, ERCOT shall use the Output Schedule available at the SCED snapshot for the execution of the SCED and shall assume that the scheduled MW amount in the Output Schedule is the Base Point for the DSR for that SCED interval. ERCOT shall create proxy Energy Offer Curves for the DSR under paragraph (4)(a) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(b) If the QSE representing a DSR submits an Incremental and Decremental Energy Offer Curve under Section 6.4.5, Incremental and Decremental Energy Offer Curves, then ERCOT shall use the Incremental and Decremental Energy Offer Curve to create proxy Energy Offer Curves for the DSR under paragraph (4)(b) of Section 6.5.7.3.

(c) For a DSR that is dispatched to a Base Point other than its Output Schedule for that SCED interval, the Base-Point Deviation Charge under Section 6.6.5.1, Resource Base Point Deviation Charge, applies:

(i) Beginning after four consecutive, complete 15-minute Settlement Intervals have occurred after the DSR is dispatched to a Base Point other than its Output Schedule; and

(ii) Ending when the DSR is no longer dispatched to a Base Point other than its Output Schedule.

(d) After the DSR is no longer dispatched to a Base Point other than its Output Schedule, the 15 MW or 15% limit, whichever is greater, under paragraph (3) of Section 6.4.2.3, Output Schedule Criteria, does not apply to the DSR until four consecutive, complete 15-minute Settlement Intervals have occurred after the DSR is no longer dispatched to a Base Point other than its Output Schedule.

[NPRR1000: Delete Section 6.4.2.2 above upon system implementation and renumber accordingly.]

6.4.2.3 Output Schedule Criteria

(1) An Output Schedule submitted by a QSE for a Resource must include the following:

(a) The name of the Entity submitting the Output Schedule for the Resource;

(b) The name of the Resource;

(c) The desired MW output level for each five-minute interval for the Resource for all of the remaining five-minute intervals in the Operating Day for which an Energy Offer Curve has not been submitted.

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

(c) The desired MW output level for each five-minute interval for the Resource for all of the remaining five-minute intervals in the Operating Day for which an Energy Offer Curve or Energy Bid/Offer Curve has not been submitted.

(2) ERCOT must reject an Output Schedule for a Resource if an Energy Offer Curve corresponding to any period in the Output Schedule exists;

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

(2) ERCOT must reject an Output Schedule for a Resource if an Energy Offer Curve or Energy Bid/Offer Curve corresponding to any period in the Output Schedule exists;

(3) For a QSE representing one or more DSRs, the sum of all Output Schedules (excluding Ancillary Services energy deployments, energy deployed through Dispatch Instructions, and Energy Trades) for the QSE must be within 15% or 15 MW (whichever is greater) of the aggregate telemetered DSR Load;

[NPRR1000: Delete paragraph (3) above upon system implementation and renumber accordingly.]

(4) The MW difference between Output Schedules for any two consecutive five-minute intervals must be less than ten times the SCED Up Ramp Rate (SURAMP) for schedules showing an increase from the prior period and the SCED Down Ramp Rate (SDRAMP) for schedules showing a decrease from the prior period.

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

(4) The MW difference between Output Schedules for any two consecutive five-minute intervals must be less than ten times the Normal Ramp Rate up for schedules showing an increase from the prior period and the Normal Ramp Rate down for schedules showing a decrease from the prior period.

(5) The Output Schedule for each interval in the Operating Period must be less than or equal to the Resource's High Sustained Limit (HSL) and must be greater than or equal to the Resource's Low Sustained Limit (LSL) for the corresponding hour.

6.4.2.4 Output Schedule Validation

(1) A validated Output Schedule is a schedule that ERCOT has determined meets the criteria listed in Section 6.4.2.3, Output Schedule Criteria.

(2) ERCOT shall notify the QSE submitting an Output Schedule by the Messaging System if the schedule was rejected or was considered invalid for any reason. The QSE may then resubmit the schedule within the appropriate market timeline.

(3) ERCOT shall continuously validate Output Schedules and continuously display on the Market Information System (MIS) Certified Area information that allows any QSE to view its valid Output Schedule.

(4) If a valid Output Schedule does not exist for a Resource that has a status of On-Line DSR at the time of SCED execution, then ERCOT shall notify the QSE and set the Output Schedule equal to the telemetered output of the Resource until a revised Output Schedule is validated.

[NPRR1000: Delete paragraph (4) above upon system implementation and renumber accordingly.]

(5) For Generation Resources with a Resource Status other than ONTEST, STARTUP, or SHUTDOWN, if a valid Energy Offer Curve or an Output Schedule does not exist for a non-DSR that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then current telemetered

output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period.

[NPRR1046: Replace paragraph (5) above with the following upon system implementation of NPRR1000:]

(5) For Generation Resources with a Resource Status other than ONTEST, STARTUP, or SHUTDOWN, if a valid Energy Offer Curve or an Output Schedule does not exist for a Resource that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period.

6.4.2.5 DSR Load

(1) A QSE may designate a Resource in the Current Operating Plan (COP) and through the telemetered Resource Status as a participant in the QSE's control of DSR Load under the requirements in Section 16.2.3.1, Process to Gain Approval to Follow DSR Load.

(2) Each QSE may not have more than one DSR Load.

(3) The following principles for DSR Load apply:

(a) All power signals for DSR Load must be sent to ERCOT in Real-Time by telemetry; and

(b) If a DSR Load signal is lost for any reason for a period greater than one 15-minute Settlement Interval, then ERCOT shall notify the QSE and suspend validation of DSR Output Schedules. If the DSR Load signal fails for more than ten consecutive hours, ERCOT shall suspend the QSE's ability to use DSRs until the signal is reliably restored (as determined by ERCOT). If the signal failure is identified to be an ERCOT communication problem, ERCOT may not suspend the QSE's ability to use DSRs.

[NPRR1000: Delete Section 6.4.2.5 above upon system implementation.]

6.4.3 Real-Time Market (RTM) Energy Bids and Offers

6.4.3.1 RTM Energy Bids

(1) A QSE may submit Controllable Load Resource-specific Real-Time Market (RTM) Energy Bids by the end of the Adjustment Period on behalf of a Load Serving Entity (LSE) representing a Controllable Load Resource.

[NPRR1058: Delete paragraph (1) above upon system implementation and renumber accordingly.]

(2) An RTM Energy Bid represents the willingness to buy energy at or below a certain price, not to exceed the System-Wide Offer Cap (SWCAP), for the Demand response capability of a Controllable Load Resource in the RTM.

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

(2) An RTM Energy Bid represents the willingness to buy energy at or below a certain price, not to exceed the effective Value of Lost Load (VOLL), for the Demand response capability of a Controllable Load Resource in the RTM.

(3) RTM Energy Bids remain active for the offered period until either:

(a) Selected by ERCOT; or

(b) Automatically inactivated at the offer expiration time specified in the RTM Energy Bid.

[NPRR1058: Replace paragraph (3) above with the following upon system implementation:]

(3) RTM Energy Bids remain active for the offered period until automatically inactivated at the offer expiration time specified in the RTM Energy Bid.

(4) For any Operating Hour, the QSE may submit or change an RTM Energy Bid in the Adjustment Period. If, by the end of the Adjustment Period, the QSE has not submitted a valid RTM Energy Bid, ERCOT shall create a proxy RTM Energy Bid for the entire Demand response capability of that Load Resource with a not-to-exceed price at the SWCAP.

[NPRR1058: Replace paragraph (4) above with the following upon system implementation:]

(4) For any Operating Hour, the QSE may submit or change an RTM Energy Bid at any time prior to SCED execution, and SCED will use the latest updated RTM Energy Bid available in the system. If a new RTM Energy Bid is not deemed to be valid, then the most recent valid RTM Energy Bid available in the system at the time of SCED execution will be used and ERCOT will notify the QSE that the invalid RTM Energy Bid was rejected. Once an Operating Hour ends, an RTM Energy Bid for that hour cannot be submitted, updated, or canceled.

(5) If the QSE has not submitted a valid RTM Energy Bid for an Operating Hour, ERCOT shall create a proxy RTM Energy Bid for the entire Demand response capability of that Load Resource with a not-to-exceed price at the SWCAP.

[NPRR1010: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) For any Operating Hour, the QSE may submit or change an RTM Energy Bid in the Adjustment Period. If, by the end of the Adjustment Period, the QSE has not submitted a valid RTM Energy Bid, ERCOT shall create a proxy RTM Energy Bid for the entire Demand response capability of that Load Resource with a not-to-exceed price at the effective VOLL.

(5) The QSE may remove the Controllable Load Resource from SCED Dispatch by changing the Load Resource's telemetered Resource Status or ramp rates appropriately. The QSE will update the COP Resource Status accordingly as soon as practicable.

(6) Notwithstanding any other provisions in this subsection, a QSE representing an Energy Storage Resource (ESR) may submit or update its RTM Energy Bid for that ESR at any time prior to SCED execution, and SCED will use the latest updated RTM Energy Bid available in the system. If a new RTM Energy Bid is not deemed to be valid, then the most recent valid RTM Energy Bid available in the system at the time of SCED execution will be used and ERCOT will notify the QSE that the invalid RTM Energy Bid was rejected. Once an Operating Hour ends, an RTM Energy Bid for that hour cannot be submitted, updated, or canceled.

[NPRR1058: Delete paragraph (6) above upon system implementation.]

6.4.3.1.1 RTM Energy Bid Criteria

(1) Each RTM Energy Bid submitted by a QSE must include the following information:

(a) The QSE;

(b) The relevant Load Resource;

(c) A bid curve with no more than ten price/quantity pairs with monotonically non-increasing not-to-exceed prices (in $/MWh) and with increasing quantities ranging from zero to the Load Resource's maximum demand response capability (in MW) represented by the difference between the Load Resource's telemetered Maximum Power Consumption (MPC) and Low Power Consumption (LPC);

(d) The first and last hour of the bid; and

(e) The expiration time and date of the bid.

(2) The software systems must be able to provide ERCOT with the ability to enter Resource-specific RTM Energy Bid floors and caps.

(3) The minimum amount per Load Resource for each RTM Energy Bid that may be submitted is one-tenth (0.1) MW.

(4) If a Controllable Load Resource is carrying Ancillary Service Resource Responsibility, its RTM Energy Bid must be priced no higher than the SWCAP.

[NPRR1010: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) If a Controllable Load Resource is offering to provide an Ancillary Service, its RTM Energy Bid must be priced no higher than the effective VOLL.

6.4.3.1.2 RTM Energy Bid Validation

(1) A valid RTM Energy Bid is a bid that ERCOT has determined meets the criteria listed in Section 6.4.3.1.1, RTM Energy Bid Criteria.

(2) ERCOT shall notify the QSE submitting an RTM Energy Bid by the Messaging System if the bid was rejected or was considered invalid for any reason. The QSE may then resubmit the bid within the appropriate market timeline.

(3) ERCOT shall continuously validate RTM Energy Bids and continuously display on the MIS Certified Area information that allows any QSE to view its valid RTM Energy Bids.

6.4.4 Energy Offer Curve

(1) A detailed description of Energy Offer Curve and validations performed by ERCOT is in Section 4.4.9, Energy Offers and Bids.

(2) For an On-Line RMR Unit, ERCOT shall submit an Energy Offer Curve considering contractual constraints on the Resource and any other adverse effects on, or implications arising from, the RMR Agreement, that may occur as the result of the Dispatch of the RMR Unit. The RMR Unit's Energy Offer Curve must price all energy at the SWCAP in $/MWh.

(3) For Generation Resources with a Resource Status other than ONTEST, STARTUP, or SHUTDOWN, if a valid Energy Offer Curve or an Output Schedule does not exist for a Resource that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE. Except for IRRs, QF Resources, and DSRs, ERCOT shall create an Output Schedule equal to the then-current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period.

[NPRR1000, NPRR1010, NPRR1014, and NPRR1058: Replace applicable portions of Section 6.4.4 above with the following upon system implementation for NPRR1000, NPRR1014, or NPRR1058; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.4.4 Energy Offer Curve and Energy Bid/Offer Curve

(1) A detailed description of Energy Offer Curve, Energy Bid/Offer Curve, and validations performed by ERCOT is in Section 4.4.9, Energy Offers and Bids.

(2) For an On-Line RMR Unit, ERCOT shall submit an Energy Offer Curve considering contractual constraints on the Resource and any other adverse effects on, or implications arising from, the RMR Agreement, that may occur as the result of the Dispatch of the RMR Unit. The RMR Unit's administratively-set Energy Offer Curve must price all energy at the effective VOLL in $/MWh.

(3) For Generation Resources with a Resource Status other than ONTEST, STARTUP, or SHUTDOWN, if a valid Energy Offer Curve or an Output Schedule does not exist for a Resource that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE. Except for IRRs and QF Resources, ERCOT shall create an Output Schedule equal to the then-current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted.

(4) For ESRs with a Resource Status other than ONTEST or ONHOLD, if a valid Energy Bid/Offer Curve or an Output Schedule does not exist, then ERCOT shall notify the QSE and create a proxy Energy Bid/Offer Curve priced at -$250/MWh for the MW portion of the curve less than zero MW, and priced at the RTSWCAP for the MW portion of the curve greater than zero MW.

6.4.4.1 Energy Offer Curve for On-Line Non-Spinning Reserve Capacity

(1) The following applies to Generation Resources that a QSE assigns Non-Spinning Reserve (Non-Spin) Ancillary Service Resource Responsibility in its COP to meet the QSE's Ancillary Service Supply Responsibility for Non-Spin and applies to On-Line Non-Spin assignments arising as the result of Day-Ahead Market (DAM) or Supplemental Ancillary Services Market (SASM) Ancillary Service awards, or Self-Arranged Ancillary Service Quantity.

(a) Prior to the end of the Adjustment Period for an Operating Hour during which a Generation Resource is assigned On-Line Non-Spin Ancillary Service Resource Responsibility, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to Non-Spin may not be offered at less than $75 per MWh.

[NPRR1058: Replace paragraph (a) above with the following upon system implementation:]

(a) For an Operating Hour during which a Generation Resource is assigned On-Line Non-Spin Ancillary Service Resource Responsibility, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to Non-Spin may not be offered at less than $75 per MWh.

(b) If the QSE also assigns Responsive Reserve (RRS) and/or Regulation Up Service (Reg-Up) to a Generation Resource that has been assigned Non-Spin, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to the sum of the RRS, Reg-Up, and Non-Spin Ancillary Service Resource Responsibilities, as well as any Non-Frequency Responsive Capacity (NFRC) that is above the Resource's High Ancillary Service Limit (HASL) and will not be utilized prior to deployment of a Resource's On-Line Non-Spin, may not be offered at less than $75 per MWh.

[NPRR1131: Replace Section 6.4.4.1 above with the following upon system implementation:]

6.4.4.1 Energy Offer Curve or Energy Bid Curve for On-Line Non-Spinning Reserve Capacity

(1) The following applies to Generation Resources and Controllable Load Resources that a QSE assigns Non-Spinning Reserve (Non-Spin) Ancillary Service Resource

Responsibility in its COP to meet the QSE's Ancillary Service Supply Responsibility for Non-Spin and applies to On-Line Non-Spin assignments arising as the result of Day-Ahead Market (DAM) or Supplemental Ancillary Services Market (SASM) Ancillary Service awards, or Self-Arranged Ancillary Service Quantity.

(a) Prior to the end of the Adjustment Period for an Operating Hour during which a Generation Resource is assigned On-Line Non-Spin Ancillary Service Resource Responsibility, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to Non-Spin may not be offered at less than $75 per MWh.

(b) Prior to the end of the Adjustment Period for an Operating Hour during which a Controllable Load Resource is assigned On-Line Non-Spin Ancillary Service Resource Responsibility, the QSE shall ensure that an Energy Bid Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Bid Curve submitted by the QSE for the capacity assigned to Non-Spin may not be less than $75 per MWh.

(c) If the QSE also assigns Responsive Reserve (RRS) and/or Regulation Up Service (Reg-Up) to a Generation Resource that has been assigned Non-Spin, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to the sum of the RRS, Reg-Up, and Non-Spin Ancillary Service Resource Responsibilities, as well as any Non-Frequency Responsive Capacity (NFRC) that is above the Resource's High Ancillary Service Limit (HASL) and will not be utilized prior to deployment of a Resource's On-Line Non-Spin, may not be offered at less than $75 per MWh.

(d) If the QSE also assigns RRS and/or Reg-Up to a Controllable Load Resource that has been assigned Non-Spin, the QSE shall ensure that a valid Energy Bid Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Bid Curves submitted by the QSE for the capacity assigned to the sum of the RRS, Reg-Up, and Non-Spin Ancillary Service Resource Responsibilities may not be less than $75 per MWh.

[NPRR1010: Delete Section 6.4.4.1 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.4.4.2 Energy Offer Curve for RUC-Committed Switchable Generation Resources

(1) Prior to the end of the Adjustment Period for an Operating Hour during which a Switchable Generation Resource (SWGR) has been committed by ERCOT as part of the Reliability Unit Commitment (RUC) process to address an actual or anticipated Energy Emergency Alert (EEA) event, the QSE shall ensure that an Energy Offer Curve that prices all energy from LSL to HSL at or above $4,500 per MWh or at the SWCAP, whichever is lower, for the Operating Hours in the RUC commitment period, has been submitted and accepted by ERCOT.

[NPRR1058: Replace paragraph (1) above with the following upon system implementation:]

(1) For an Operating Hour during which a Switchable Generation Resource (SWGR) has been committed by ERCOT as part of the Reliability Unit Commitment (RUC) process to address an actual or anticipated Energy Emergency Alert (EEA) event, the QSE shall ensure that an Energy Offer Curve that prices all energy from LSL to HSL at or above $4,500 per MWh or at the SWCAP, whichever is lower, for the Operating Hours in the RUC commitment period, has been submitted and accepted by ERCOT.

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

(1) Prior to the end of the Adjustment Period for an Operating Hour during which a Switchable Generation Resource (SWGR) has been committed by ERCOT as part of the Reliability Unit Commitment (RUC) process to address an actual or anticipated Energy Emergency Alert (EEA) event, ERCOT shall administratively set an Energy Offer Curve that prices all energy from LSL to HSL at or above $4,500 per MWh, or at the effective VOLL, whichever is lower, for the Operating Hours in the RUC commitment period.

[NPRR1019: Delete Section 6.4.4.2 above upon system implementation.]

6.4.5 Incremental and Decremental Energy Offer Curves

(1) A QSE for a DSR may submit an Incremental Energy Offer Curve and a Decremental Energy Offer Curve in addition to the Output Schedule for the DSR. The Incremental and Decremental Energy Offer Curves prices must be within the range of -$250.00 per MWh and the SWCAP in dollars per MWh with the quantity within the range of the High Reasonability Limit (HRL) and Low Reasonability Limit (LRL), which are described in the Resource Registration Glossary and provided in Resource Registration data. The first price/quantity pair for both the Incremental and Decremental Energy Offer Curves must provide an energy price at LRL and the last price/quantity pair must provide a price at

HRL. At every MW value of the curves, the price of the Incremental Energy Offer Curve must be greater than the Decremental Energy Offer Curve. Incremental and Decremental Energy Offer Curves are subject to the same requirements for the same criteria and validations performed by ERCOT as provided in Section 4.4.9, Energy Offers and Bids.

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

(1) A QSE for a DSR may submit an Incremental Energy Offer Curve and a Decremental Energy Offer Curve in addition to the Output Schedule for the DSR. The Incremental and Decremental Energy Offer Curves prices must be within the range of -$250.00 per MWh and the RTSWCAP in dollars per MWh with the quantity within the range of the High Reasonability Limit (HRL) and Low Reasonability Limit (LRL), which are described in the Resource Registration Glossary and provided in Resource Registration data. The first price/quantity pair for both the Incremental and Decremental Energy Offer Curves must provide an energy price at LRL and the last price/quantity pair must provide a price at HRL. At every MW value of the curves, the price of the Incremental Energy Offer Curve must be greater than the Decremental Energy Offer Curve. Incremental and Decremental Energy Offer Curves are subject to the same requirements for the same criteria and validations performed by ERCOT as provided in Section 4.4.9, Energy Offers and Bids.

[NPRR1000: Replace Section 6.4.5 above with the following upon system implementation:]

6.4.5 [RESERVED]

6.4.6 Resource Status

(1) ERCOT shall use the telemetered Resource Status for all applications requiring status of Resources during the Operating Hour, including SCED and Load Frequency Control (LFC). QSEs shall provide ERCOT with accurate telemetry of the current capability of each Resource including the Resource Status, Ramp Rates, HSL, and LSL.

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

(1) ERCOT shall use the telemetered Resource Status for all applications requiring status of Resources during the Operating Hour, including SCED and Load Frequency Control (LFC). QSEs shall provide ERCOT with accurate telemetry of the current capability of each Resource including the Resource Status, Ancillary Service capability for each Ancillary Service, Ramp Rates, HSL, and LSL.

(2) ERCOT shall perform the following validations during the Operating Period:

(a) Each QSE shall provide the Real-Time operating status of each Resource to ERCOT by telemetry using the status codes in the COP for Real-Time as described in Section 3.9, Current Operating Plan (COP); and

(b) Five minutes before the end of each hour, ERCOT shall identify inconsistencies between the telemetered Resource Status and the Resource Status stated in the COP for that Resource in the next hour. On detecting an inconsistency, ERCOT shall provide a notice of inconsistent Resource Status to the QSE using the Messaging System.

6.4.7 QSE-Requested Decommitment of Resources and Changes to Ancillary Service Resource Responsibility of Resources

(1) A Resource must remain committed during any RUC-Committed Interval or RUC Buy-Back Hour unless the Resource has a Forced Outage.

(2) In the Operating Period, a QSE may request to decommit a Resource other than a Quick Start Generation Resource (QSGR) for any interval that is not a RUC-Committed Interval or RUC Buy-Back Hour by verbally requesting ERCOT to consider its request.

(3) In the Operating Period, a QSE may decommit a QSGR without any request for any interval that is neither a RUC-Committed Interval, a RUC Buy-Back Hour, nor an interval in which a manual override by the ERCOT Operator has been given.

(4) In the Adjustment Period, a QSE may request to decommit a Resource for any interval that is not a RUC-Committed Interval or RUC Buy-Back Hour by indicating a change in unit status in the QSE’s COP, unless the Resource received a Weekly Reliability Unit Commitment (WRUC) instruction for the hour. A QSE may request to decommit a Resource for any interval that is a WRUC-instructed Interval and that is not a RUC-Committed Interval or RUC Buy-Back Hour by verbally requesting ERCOT to consider its request.

(5) In the Adjustment Period, a QSE may request ERCOT approval for moving an Ancillary Service Resource Responsibility from one Resource to another Resource by changing its COP, provided that the QSE complies with its total Ancillary Service Supply Responsibility. Any Ancillary Services transfer must be in alignment with the allowable Ancillary Service Trades, as described in Section 4.4.7.3, Ancillary Service Trades. A QSE may transfer Ancillary Service Resource Responsibility for any Ancillary Service to an eligible Resource that has been opted out of RUC Settlement. ERCOT shall use the Hourly Reliability Unit Commitment (HRUC) and other processes to study the move and if Ancillary Services become infeasible as a result of the proposed move, ERCOT shall follow the provisions of Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints.

[NPRR1092: Replace paragraph (5) above with the following upon system implementation:]

(5) In the Adjustment Period, a QSE may request ERCOT approval for moving an Ancillary Service Resource Responsibility from one Resource to another Resource by changing its COP, provided that the QSE complies with its total Ancillary Service Supply Responsibility. Any Ancillary Services transfer must be in alignment with the allowable Ancillary Service Trades, as described in Section 4.4.7.3, Ancillary Service Trades. A QSE may transfer Ancillary Service Resource Responsibility for any Ancillary Service to an eligible Resource that has been opted out of RUC Settlement. ERCOT shall use the Hourly Reliability Unit Commitment (HRUC) and other processes to study the move and if Ancillary Services become infeasible as a result of the proposed move, ERCOT shall follow the provisions of Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints.

(6) In the Operating Period, a QSE shall only provide an Ancillary Service from a Resource which was reported to ERCOT in the COP to be providing that Ancillary Service for the effective Operating Hour unless modified pursuant to paragraph (7) below.

(7) A QSE may vary the quantity of the Ancillary Service Resource Responsibility on Resources, through telemetry, during the time window beginning 30 seconds prior to a five-minute clock interval and ending ten seconds prior to that five-minute clock interval, provided that the QSE complies with its total Ancillary Service Supply Responsibility. Any Ancillary Services transfer must be in alignment with the allowable Ancillary Service Trades, as described in Section 4.4.7.3.

[NPRR1010: Replace Section 6.4.7 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.4.7 QSE-Requested Decommitment of Resources

(1) A Resource must remain committed during any RUC-Committed Interval or RUC Buy-Back Hour unless the Resource has a Forced Outage.

(2) In the Operating Period, a QSE may request to decommit a Resource other than a Quick Start Generation Resource (QSGR) for any interval that is not a RUC-Committed Interval or RUC Buy-Back Hour by verbally requesting ERCOT to consider its request.

(3) In the Operating Period, a QSE may decommit a QSGR without any request for any interval that is neither a RUC-Committed Interval, a RUC Buy-Back Hour, nor an interval in which a manual override by the ERCOT Operator has been given.

(4) In the Adjustment Period, a QSE may request to decommit a Resource for any interval that is not a RUC-Committed Interval or RUC Buy-Back Hour by indicating a change

in unit status in the QSE's COP, unless the Resource received a Weekly Reliability Unit Commitment (WRUC) instruction for the hour. A QSE may request to decommit a Resource for any interval that is a WRUC-instructed Interval and that is not a RUC-Committed Interval or RUC Buy-Back Hour by verbally requesting ERCOT to consider its request.

6.4.7.1 QSE Request to Decommit Resources in the Operating Period

(1) For a request made during the Operating Period to decommit a Resource, ERCOT may perform a study using Real-Time conditions to determine if ERCOT will remain n-1 secure with that Resource Off-Line. ERCOT may grant the request provided the Resource is not providing any Ancillary Service Resource Responsibility and if analysis indicates the Resource Outage contingency results in no additional active constraints for SCED. ERCOT may only approve requests that do not have a reliability impact.

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

(1) For a request made during the Operating Period to decommit a Resource, ERCOT may perform a study using Real-Time conditions to determine if ERCOT will remain n-1 secure with that Resource Off-Line. ERCOT may grant the request provided the analysis indicates the Resource Outage contingency results in no additional active constraints for SCED. ERCOT may only approve requests that do not have a reliability impact.

(2) If more units are requesting decommitment than can be accommodated, ERCOT shall review the requests in order of receipt.

6.4.7.2 QSE Request to Decommit Resources in the Adjustment Period

(1) To decommit an otherwise available Resource for hours other than the Operating Period, the QSE must update the COP indicating the change in Resource Status for each hour in the COP for the remaining hours in the Adjustment Period. On detection of a change from On-Line to Off-Line Available state in future hours for a Resource, ERCOT shall review all requests for decommitment using the next scheduled HRUC. The Resource must be shown as available for HRUC commitment. ERCOT shall also review the list of Off-Line Available Resources with a start-up time of one hour or less. The next HRUC commitment must consider the Resource's Minimum-Energy Offer excluding the Resource's Startup Offer from the Three-Part Supply Offer.

(2) If HRUC continues to require the Resource to be committed, ERCOT shall notify the QSE, using the process described in Section 5.5.3, Communication of RUC

Commitments and Decommitments, that the decommitment has been denied, and the affected intervals become RUC-Committed Intervals instead of QSE-Committed Intervals for RUC Settlement purposes. The QSE must update its COP to denote the RUC-Committed Intervals.

6.4.8 Notification of Forced Outage of a Resource

(1) In the event of a Forced Outage of a Resource, the telemetered status of the Resource automatically notifies ERCOT of the event. In the event of a Forced Outage, an impending Forced Outage, or de-rating of a Resource, the QSE shall inform ERCOT of the following:

(a) Time of expected change in Resource Status or rating;

(b) Text message describing the nature of the Forced Outage or de-rating updated as new information becomes available; and

(c) The expected minimum and maximum duration of the Forced Outage or de-rating.

[NPRR1085: Replace paragraph (1) above with the following upon system implementation:]

(1) In the event of a Forced Outage of a Resource, the telemetered status of the Resource automatically notifies ERCOT of the event. In the event of a Forced Outage, the telemetered Resource Status shall be changed to the appropriate Off-Line status as soon as practicable but no longer than 15 minutes after the Forced Outage occurs.

(2) In the event of a Forced Outage or an impending Forced Outage, the Resource Entity or its designee shall inform ERCOT of the following in the Outage Scheduler:

(a) Time of expected change in Resource Status or rating;

(b) Text message describing the nature of the Forced Outage or de-rating updated as new information becomes available; and

(c) The expected minimum and maximum duration of the Forced Outage or de-rating.

(3) In the event of a Forced Outage, the QSE must update the Resource's COP as soon as practicable but no longer than 60 minutes after the Forced Outage occurs.

(4) Each QSE shall timely update the telemetered Resource Status and COP unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating the telemetered Resource Status and/or COP only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment

exists. The time for updating the telemetered Resource Status and/or COP begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

6.4.9 Ancillary Services Capacity During the Adjustment Period and in Real-Time

[NPRR1010: Replace Section 6.4.9 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.4.9 Real-Time Ancillary Service Offers and Awards

6.4.9.1 Evaluation and Maintenance of Ancillary Service Capacity Sufficiency

(1) ERCOT shall evaluate Ancillary Service requirements and capacity sufficiency using evaluation tools including the Ancillary Services Capacity Monitor, described in Section 6.5.7.5, Ancillary Services Capacity Monitor, throughout the Adjustment Period and Operating Period.

(2) ERCOT may procure Ancillary Services in the Adjustment Period for the following reasons:

(a) Increased need of Ancillary Services capacity above that specified in the Day-Ahead;

(b) Replacement of Ancillary Services capacity that is infeasible due to transmission constraints; or

(c) Replacement of Ancillary Services capacity due to failure to provide.

(3) A QSE may change the specific Resources supplying Ancillary Services under Section 3.9, Current Operating Plan (COP), using the QSE's Ancillary Service Resource Responsibility in the COP only if, in ERCOT's determination, that change does not adversely affect the feasibility of the service(s) being allocated to an alternate Resource and if that change does not adversely affect the feasibility of other services previously procured by ERCOT. A QSE may not change the quantity provided of each type of Ancillary Services awarded through the ERCOT procurement process or the aggregate Self-Arranged Ancillary Service Quantity (by Ancillary Service type) from the DAM. On detection of a change in COP for Resources providing Ancillary Services, ERCOT shall review the impact on feasibility and communicate to the QSE if the change is not approved. The QSE must update its COP to reflect the ERCOT decision. If ERCOT does not act on the request by the beginning of the Operating Hour in which the change will take effect, the request is deemed approved.

[NPRR1010: Replace Section 6.4.9.1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.4.9.1 Ancillary Service Offers

(1) A detailed description of the Ancillary Service Offers and validations performed by ERCOT is in Section 4.4.7.2, Ancillary Service Offers.

(2) QSEs may update their Ancillary Service Offers in Real-Time. SCED shall use the latest updated Ancillary Service Offers available to it at the time of the SCED execution.

6.4.9.1.1 ERCOT Increases to the Ancillary Services Plan

(1) If ERCOT determines in the Adjustment Period, in its sole discretion, that more Ancillary Services are needed for one or more Operating Hours than were provided in the Day-Ahead Ancillary Services Plan, it shall notify each QSE of its increased Ancillary Service Supply Obligation.

(2) ERCOT may procure more Ancillary Services through a SASM, as described below in Section 6.4.9.2, Supplemental Ancillary Services Market, if the Self-Arranged Ancillary Service quantities are insufficient to meet the total Ancillary Service Supply Obligation.

(3) When a SASM has been executed in response to ERCOT increasing the Ancillary Services Plan, each QSE that purchases Ancillary Service capacity shall be charged its share of the net cost incurred for that service, in accordance with Section 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement.

[NPRR1010: Replace Section 6.4.9.1.1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.4.9.1.1 Ancillary Service Awards

(1) Ancillary Service awards will based on Resource capability (qualification, operating limits, Ancillary Service limits, ramp rates, etc.) and Ancillary Service Demand Curves (ASDCs) regardless of the quantity of Ancillary Service under deployment.

(2) QSEs representing Resources that are qualified to provide an Ancillary Service must submit valid Ancillary Service Offers for use in Real-Time clearing. QSEs shall submit Resource-specific telemetry indicating the Resource's ability to provide Ancillary Service in Real-Time.

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

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

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

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

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

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

6.4.9.1.2 Replacement of Infeasible Ancillary Service Due to Transmission Constraints

(1) The HRUC process must honor the High Ancillary Service Limit (HASL) and Low Ancillary Service Limit (LASL) for each Resource for each hour of the RUC Study Period unless by doing so a transmission constraint exists where the capacity reserved to provide Ancillary Services from the Resource is needed to resolve the constraint that cannot be resolved by any other means. In such cases, the Ancillary Services may be determined to be infeasible. The Ancillary Services from a Resource may also be determined to be infeasible if the deployment of those Ancillary Services would have a consistent, negative impact on a transmission constraint. Infeasibility may be identified in either the Adjustment Period or the Operating Period. If the ERCOT Operator decides that the Ancillary Service capacity allocated to that Resource is infeasible based on

ERCOT System conditions, then ERCOT shall provide the following information to each affected QSE:

(a) The amount by which the QSE must reduce the Ancillary Services currently allocated to each affected Resource; and

(b) The start and stop times of the reduction.

(2) Upon notification, each affected QSE may do one or more of the following:

(a) Substitute capacity from other Resources represented by that QSE to meet its Ancillary Services Supply Responsibility;

(b) Substitute capacity from other QSEs using Ancillary Service Trades; or

(c) Inform ERCOT that all or part of the Ancillary Services capacity needs to be replaced.

(3) If a QSE elects to substitute capacity, ERCOT shall determine the feasibility of the substitution. If the substitution is deemed infeasible by ERCOT or the QSE informs ERCOT that the Ancillary Services capacity needs to be replaced, then ERCOT shall procure, if in its sole discretion it finds that the service is still needed, the Ancillary Services capacity required under Section 6.4.9.2, Supplemental Ancillary Services Market.

(4) Settlement of infeasible Ancillary Services shall be performed in accordance with Section 6.7.2.1, Charges for Infeasible Ancillary Service Capacity Due to Transmission Constraints, and Section 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement. These calculations occur for all hours for which the Ancillary Service has been determined to be infeasible, regardless of whether or not a SASM is executed for that specific hour.

[NPRR1010: Delete Section 6.4.9.1.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.4.9.1.3 Replacement of Ancillary Service Due to Failure to Provide

(1) ERCOT may procure Ancillary Services to replace those of a QSE that has failed on its Ancillary Services Supply Responsibility through a SASM, as described below in Section 6.4.9.2, Supplemental Ancillary Services Market. A QSE is considered to have failed on its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's Resource-specific Ancillary Service capacity will not be available in Real-Time. This Section does not apply to a failure to provide caused by events described in Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints.

(2) Within a time frame acceptable to ERCOT, each affected QSE may either substitute capacity to meet its Ancillary Services Supply Responsibility or inform ERCOT that the Ancillary Services capacity needs to be replaced. If a QSE elects to substitute capacity, ERCOT shall determine the feasibility of the substitution. If the substitution is deemed infeasible by ERCOT or the QSE informs ERCOT that the Ancillary Services capacity needs to be replaced, then ERCOT shall procure, if in its sole discretion it finds that the service is still needed, the Ancillary Services capacity required under Section 6.4.9.2.

(3) ERCOT shall charge each QSE that has failed according to paragraph (1) on its Ancillary Service Supply Responsibility for a particular Ancillary Service for a specific hour.

(4) A Load Resource that is not a Controllable Load Resource shall not simultaneously provide RRS and Non-Spin on the same Load Resource in Real-Time. ERCOT may, in its sole discretion, evaluate whether the simultaneous provision of RRS and Non-Spin results in the QSE failing on its RRS or Non-Spin Ancillary Service Supply Responsibility.

[NPRR1010: Delete Section 6.4.9.1.3 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

[NPRR1010: Insert Section 6.4.9.1.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.4.9.1.2 Changes to Operating Day Ancillary Service Plan

(1) Any time during the Adjustment Period or Operating Period, if ERCOT determines that the Ancillary Service Plan needs to be modified, ERCOT will notify Market Participants of ERCOT's need to modify the Ancillary Service Plan and post the reliability reason for the modification in service requirements. ERCOT will also update the Ancillary Service Plan, as described in Section 4.2.1, Ancillary Service Plan and Ancillary Service Obligation, and update and post ASDCs for each impacted Ancillary Service product, as described in Section 4.2.1.1, Ancillary Service Plan.

6.4.9.2 Supplemental Ancillary Services Market

(1) During the Adjustment Period, ERCOT may procure additional Regulation-Up (Reg-Up), Regulation Down (Reg-Down), Responsive Reserve (RRS), and Non-Spin services for the reasons, and in the amounts, specified in Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency, using a SASM.

[NPRR863: Replace paragraph (1) above with the following upon system implementation:]

(1) During the Adjustment Period, ERCOT may procure additional Regulation-Up (Reg-Up), Regulation Down (Reg-Down), ERCOT Contingency Reserve Service (ECRS), Responsive Reserve (RRS), and Non-Spin services for the reasons, and in the amounts, specified in Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency, using a SASM.

(2) ERCOT shall allow QSEs to request to modify their Ancillary Service positions through a Reconfiguration Supplemental Ancillary Services Market (RSASM). The RSASM is executed at 0900 daily. This RSASM allows QSEs to potentially change their Ancillary Service Supply Responsibility from hour ending 1300 through hour ending 2400 of the current Operating Day. QSEs attempt to reduce their Ancillary Service Supply Responsibility through the RSASM by submitting less Ancillary Service capacity in their Resource's COPs than their Ancillary Service Supply Responsibility. The difference between the Ancillary Service Supply Responsibility and the COP Ancillary Service capacity is the reconfiguration amount that is procured by the RSASM. The QSE must also have valid Ancillary Service Offers of an amount equal to or greater than their requested reconfiguration amount. The RSASM shall not be executed if there are not enough offers to procure the Ancillary Service reconfiguration amount.

(3) The SASM process for acquiring more Ancillary Service capacity or an Ancillary Service reconfiguration must use the following timelines:

(a) For Ancillary Service capacity related to ERCOT desired increases, for replacement of Ancillary Service capacity related to infeasibility or for failure of a QSE to provide one or more Ancillary Services, ERCOT shall send a notice, by ERCOT Hotline and electronic communication, at time X to all QSEs of the SASM. Time X may be any time not less than two hours before the start of the Operating Hour for which the additional Ancillary Services capacity are being procured. For cases of Ancillary Service capacity being infeasible or for failure of a QSE to provide one or more Ancillary Services, the Operating Hours covered by the SASM may be a subset of the Operating Hours for which the Ancillary Service capacity is declared infeasible or failed.

SASM Process	**QSE Activities:**	**ERCOT Activities:**
Time = X		Notify all QSEs of intent to procure Ancillary Services by ERCOT Hotline and electronic communication. Notify QSEs of any additional Ancillary Service Obligation, allocated to each LSE and aggregated to the QSE level.
Time = X plus 30 minutes	May submit additional Self-Arranged Ancillary Service Quantities pursuant to Section 4.4.7.1, Self-Arranged Ancillary Service Quantities	Determine the amount of Ancillary Services to be procured.

Time = X plus 35 minutes		Execute SASM.
Time = X plus 45 minutes		Notify QSEs with awards of results. Post the quantities and Market Clearing Prices for Capacity (MCPCs) of Ancillary Services bought in the SASM.
Time = X plus 60 minutes	Submit updated COP with updated Ancillary Service Resource Responsibility.	Validate COPs for Ancillary Service Resource Responsibility.

(b) For an Ancillary Services reconfiguration, ERCOT shall execute an RSASM at 0900 (time E), for hour ending 1300 through hour ending 2400 of the current Operating Day.

SASM Process	**QSE Activities:**	**ERCOT Activities:**
Time = E – 15 minutes	QSEs nominate quantities of Ancillary Services that shall be included in the RSASM by submitting COPs with less Ancillary Service capacity than their Ancillary Service Supply Responsibility and submitting Ancillary Service Offers to cover the difference between the Ancillary Service Supply Responsibility and COP Ancillary Service capacity.	ERCOT sets the quantities of Ancillary Services to be procured in the RSASM equal to the difference between total Ancillary Service Supply Responsibility and total COP Ancillary Service capacity.
Time = E		Execute RSASM for hour ending 1300 through hour ending 2400 of the current Operating Day.
Time = E plus 15 minutes		Notify QSEs with awards of results. Post the quantities and MCPCs of Ancillary Services bought in the RSASM.
Time = E plus 30 minutes	Submit updated COP with updated Ancillary Service Resource Responsibility.	Validate COPs for Ancillary Service Resource Responsibility.

(4) Each QSE that is awarded capacity in a SASM is paid the SASM MCPC for the quantity it is awarded.

(5) For purpose of Settlement, the reduction to the Ancillary Service Supply Responsibility is considered a failure quantity and each QSE that has their Ancillary Service Supply Responsibility reduced by an RSASM is charged in accordance with Sections 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide, and 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement. QSEs participating in RSASMs are not subject to performance metrics for “failure to provide” amounts until the end of the Adjustment Period for each hour cleared in the RSASM.

(6) ERCOT shall allocate additional Ancillary Service Obligations to QSEs using the same percentages as the original Day-Ahead allocation of Ancillary Service Obligations.

[NPRR1010: Delete Section 6.4.9.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.4.9.2.1 Resubmitting Offers for Ancillary Services in the Adjustment Period

(1) During the Adjustment Period, a QSE may resubmit an offer for an Ancillary Service that it submitted for a Resource but was not struck in a previous market. The resubmitted offer for that Resource may be submitted at any price subject to applicable offer caps and offer floors to be considered a valid offer in any subsequent market.

[NPRR1010: Delete Section 6.4.9.2.1 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.4.9.2.2 SASM Clearing Process

(1) SASM procurement requirements are:

(a) ERCOT shall procure the additional quantity required of each Ancillary Service, less the quantity self-arranged, if applicable. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service.

(b) ERCOT shall select Ancillary Service Offers submitted by QSEs, such that:

(i) For each Ancillary Service being procured, other than Reg-Down, ERCOT shall select offers that minimize the overall offer-based cost of these Ancillary Services. For each of these Ancillary Services, if selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(ii) For Reg-Down, ERCOT shall procure required quantities by selecting capacity in ascending order starting from the lowest-priced offer. ERCOT shall continue this selection process until the required quantity of Reg-Down is obtained. If selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(iii) For each Ancillary Service Offer from an Off-Line Resource considered in a SASM, the offer will be awarded only if it can meet the start-up time of the Resource based on the current and the historical operational state of the Resource. If the start-up time cannot be met for the first hour of a block offer, then the whole block offer shall not be considered.

(c) If a QSE has submitted offers of the same Resource capacity for more than one Ancillary Service (sometimes called linked offers), ERCOT may not select any one part of that Resource capacity to provide more than one Ancillary Service in the same Operating Hour. ERCOT may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service in the same Operating Hour.

(d) The SASM MCPC for each hour for each service is the Shadow Price for the corresponding Ancillary Service constraint for the hour as determined by the SASM algorithm.

(e) SASM MCPCs for any Ancillary Service shall not exceed the SWCAP. Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in Appendix 2, Day-Ahead Market Optimization Control Parameters, of the Other Binding Document titled “Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints,” will not be awarded.

[NPRR1010: Delete Section 6.4.9.2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.4.9.2.3 Communication of SASM Results

(1) As soon as practicable, but no later than the time specified in Section 6.4.9.2, Supplemental Ancillary Services Market, ERCOT shall notify each QSE of its awarded Ancillary Service Offer quantities in each SASM, specifying Resource, Ancillary Service type, SASM MCPC, and first and last hours of the awarded offer.

(2) For each QSE for which ERCOT has procured replacement Ancillary Services capacity in a SASM pursuant to Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints, or Section 6.4.9.1.3, Replacement of Ancillary Service Due to Failure to Provide, ERCOT shall, as soon as practicable but no later than the time specified in Section 6.4.9.2, notify each affected QSE of the procured Ancillary Service quantities, the Ancillary Service types, and the SASM MCPCs by hour.

(3) As soon as practicable, but no later than the time specified in Section 6.4.9.2, ERCOT shall post on the ERCOT website the hourly:

(a) SASM MCPC for each type of Ancillary Service for each hour;

(b) Total Ancillary Service procured in MW by Ancillary Service type for each hour; and

(c) Aggregated Ancillary Service Offer Curve for each Ancillary Service for each hour.

[NPRR1010: Delete Section 6.4.9.2.3 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.5 Real-Time Energy Operations

6.5.1 ERCOT Activities

(1) ERCOT activities during Real-Time operations are summarized in the table located in Section 6.3.2, Activities for Real-Time Operations. That table is intended to be only a general guide and not controlling language, and any conflict between the table and another section of the Protocols is controlled by the other section.

6.5.1.1 ERCOT Control Area Authority

(1) ERCOT, as Control Area Operator (CAO), is authorized to perform the following actions for the limited purpose of securely operating the ERCOT Transmission Grid under the standards specified in North American Electric Reliability Corporation (NERC) Standards, the Operating Guides and these Protocols, including:

(a) Direct the physical operation of the ERCOT Transmission Grid, including circuit breakers, switches, voltage control equipment, and Load-shedding equipment;

(b) Dispatch Resources that have committed to provide Ancillary Services;

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

(b) Dispatch Resources that have been awarded Ancillary Services;

(c) Direct changes in the operation of voltage control equipment;

(d) Direct the implementation of Reliability Must-Run (RMR) Service, Remedial Action Plans (RAPs), Automatic Mitigation Plans (AMPs), Remedial Action Schemes (RASs), and transmission switching to prevent the violation of ERCOT Transmission Grid security limits; and

(e) Perform additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT Transmission Grid to a secure state in the event of an ERCOT Transmission Grid Emergency Condition.

(2) Unless the ERCOT Protocols or Other Binding Documents explicitly provide otherwise, ERCOT shall not model, monitor, direct operation of, or otherwise exercise any operational authority over any facility that operates on the low voltage side of the distribution transformer except as may be necessary for the following purposes:

(a) To ensure the reliable interconnection, dispatch, operation, and Settlement of any Generation Resource, Energy Storage Resource (ESR), Load Resource, or Emergency Response Service (ERS) Resource that is, or is proposed to be, interconnected at distribution voltage, and to ensure the reliable operation and Settlement of any other ERCOT-registered generator or Energy Storage System (ESS);

(b) To provide ERCOT information about all generators and ESS interconnected at distribution voltage as requested by ERCOT pursuant to these Protocols or Other Binding Documents for the purposes of ensuring accurate Settlement and operating and planning the Transmission Grid; and

(c) To effectuate automatic or manual Load-shedding as prescribed by these Protocols or Other Binding Documents.

(3) Nothing in paragraph (2) above limits ERCOT's authority to require that a Transmission Service Provider (TSP) or Transmission Operator (TO) disconnect any Facility operated at distribution voltage from the ERCOT System if ERCOT determines such action is necessary to address a reliability concern on the ERCOT Transmission Grid. Additionally, nothing in paragraph (2) above limits ERCOT's authority to require appropriate modeling and telemetry of transmission Loads that may represent multiple distribution-level Loads, as provided in Section 3.10.7.2, Modeling of Resources and Transmission Loads.

(4) Consistent with paragraph (1)(e) above, if ERCOT seeks to exercise its authority to prevent an anticipated Emergency Condition relating to serving Load in the current or next Season by procuring existing capacity that may be used to maintain ERCOT System reliability in a manner not otherwise delineated in these Protocols and the Operating Guides, ERCOT shall take the following actions:

(a) Upon determination by ERCOT that additional capacity is needed to prevent an Emergency Condition and prior to any procurement activity associated with such additional capacity, ERCOT shall issue a Notice as soon as practicable with the following information:

(i) A detailed description of the reliability condition and need for additional capacity as determined by ERCOT and the timing of the proposed procurement;

(ii) Justification for the quantity of additional capacity to be requested;

(iii) Identification of potential Generation Resources or Load providing capacity considered by ERCOT to be acceptable for providing the additional capacity. Load capacity may be provided by Entities who, at ERCOT's direction, would interrupt consumption of electric power and remain interrupted until released by ERCOT; and

(iv) A schedule of activities associated with the proposed procurement.

(b) If ERCOT identifies a specific Entity with which it will negotiate the terms for procurement of additional capacity, then ERCOT shall issue a Notice as soon as practicable that includes the Entity name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, the name of the Resource Entity, and the potential duration of any contract, including anticipated start and end dates.

(c) ERCOT shall, to the fullest extent practicable, ensure that any actions taken to procure additional capacity meet the following criteria:

(i) Any capacity procured pursuant to this paragraph will be procured using an open process, and the terms of the procurement between ERCOT and the Entity will be memorialized in contracts that will be publicly available for inspection on the ERCOT website.

(ii) Each contract will include specified financial terms and termination dates. For purposes of Settlement, any contract associated with a Generation Resource will include substantially the same terms and conditions as an RMR Unit under a RMR Agreement, including the Eligible Cost budgeting process.

(iii) ERCOT shall provide notice to the ERCOT Board, at the next ERCOT Board meeting after ERCOT has signed the contract, that the actions required prior to execution of the contract, pursuant to paragraphs (4)(a) through (c) above, were completed by ERCOT before the contract was executed.

(iv) Any information submitted by the Entity to ERCOT through the procurement process may be designated as Protected Information and treated in accordance with the provisions of Section 1.3, Confidentiality, provided that final contract terms must be made available for public inspection.

(d) A Generation Resource that has received capital contributions from ERCOT pursuant to a contract executed under this paragraph (4) may not participate in the energy or Ancillary Services markets until such capital contributions have been refunded to ERCOT. For the purposes of this Section, capital contributions are defined as improvements with an asset life greater than one year under the applicable federal tax rules. The Resource Entity's refund of capital contributions shall be a lump sum payment calculated as follows:

(i) If the Generation Resource chooses to participate in the energy or Ancillary Service markets after the termination date of the contract executed under this paragraph (4), the Qualified Scheduling Entity (QSE) representing the Resource Entity shall repay, in a lump sum payment, 100% of the book value of the capitalized equipment and all installation charges leading to turn key, one-time startup based on a linear depreciation over the estimated life of the capitalized component(s) in accordance with Generally Accepted Accounting Principles (GAAP) standards for electric utility equipment. The estimated life shall be based on documentation provided by the manufacturer; if installing used equipment, the estimated life may be based on an approximation agreed to by the Resource Entity and ERCOT.

(ii) If the Generation Resource chooses to participate in the energy or Ancillary Services markets as contemplated in item (4)(d)(i) above, and its participation requires a lump sum payment of capital contributions, ERCOT will issue a notice to all registered Market Participants announcing the Generation Resource's decision to participate in the market(s) and identifying the amount of the lump sum payment due pursuant to item (4)(d)(i) above. ERCOT will also issue a notice to all registered Market Participants after completion of the collection and disbursement of the capital contributions, as described in item (4)(d)(iii) below, and after resolution of any disputes related to these capital contributions.

(iii) After ERCOT receives a Notification of Change of Generation Resource Designation (Section 22, Attachment H, Notification of Change of Generation Resource Designation) changing the Resource designation to "operational" at a future date, ERCOT shall charge the QSE representing the Resource Entity for capital expenditures incurred and previously paid to the Resource Entity as a result of the Resource's return to service pursuant to this Section.

(A) For months in the contract term where notice is received more than five Business Days prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any payments made for the capital expenditure associated with that month and subsequent months of the term, on the next practical Settlement but no later than the True-Up Settlement.

(B) For months in the contract term where notice is received five Business Days or less prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any payments made for the capital expenditures within 45 days of receipt of the notice.

(C) ERCOT shall distribute the repayment to QSEs representing Load on the same basis used to collect the monthly capital expenditures, using a monthly Load Ratio Share (LRS). A QSE's monthly LRS shall be the QSE's total Real-Time Adjusted Metered Load (AML) for the month divided by the total ERCOT Real-Time AML for the same month.

(e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the System-Wide Offer Cap (SWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion.

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

(e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the Real-Time System-Wide Offer Cap (RTSWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion.

(f) An Entity cannot be compelled to enter into a contract under this paragraph.

6.5.1.2 Centralized Dispatch

(1) ERCOT shall centrally Dispatch Resources and Transmission Facilities under these Protocols, including deploying energy by establishing Base Points, and Emergency Base Points, and by deploying Regulation Service, Responsive Reserve (RRS) service, and Non-Spinning Reserve (Non-Spin) service to ensure operational security.

[NPRR863: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT shall centrally Dispatch Resources and Transmission Facilities under these Protocols, including deploying energy by establishing Base Points, and Emergency Base Points, and by deploying Regulation Service, ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) service to ensure operational security. Responsive Reserve (RRS) shall be self-deployed in response to frequency deviations or as specified in Nodal Operating Guide Section 4.8, Responsive Reserve Service During Scarcity Conditions.

(2) ERCOT shall verify that either an Energy Offer Curve providing prices for the Resource between its High Sustained Limit (HSL) and Low Sustained Limit (LSL) or an Output Schedule has been submitted for each On-Line Resource an hour before the end of the Adjustment Period for the upcoming Operating Hour. ERCOT shall notify QSEs that have not submitted an Output Schedule or Energy Offer Curve through the Market Information System (MIS) Certified Area.

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

(2) ERCOT shall verify that either an Energy Offer Curve or Energy Bid/Offer Curve providing prices for the Resource between its High Sustained Limit (HSL) and Low Sustained Limit (LSL) or an Output Schedule has been submitted for each On-Line Resource an hour before the end of the Adjustment Period for the upcoming Operating Hour. ERCOT shall notify QSEs that have not submitted an Output Schedule or Energy Offer Curve or Energy Bid/Offer Curve through the Market Information System (MIS) Certified Area.

[NPRR1010 and NPRR1014: Insert applicable portions of paragraph (3) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014; and renumber accordingly:]

(3) If a Resource is scheduled to be On-Line and available to provide an Ancillary Service, but does not have any Ancillary Service Offers for which the Resource is qualified to

provide, then at the end of the Adjustment Period, ERCOT shall notify the Resource's QSE through the MIS Certified Area.

(3) ERCOT may only issue Dispatch Instructions for the Real-Time operation of Transmission Facilities to a TSP, for the Real-Time operation of distribution facilities to a Distribution Service Provider (DSP), or for a Resource to the QSE that represents it.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) In Real-Time operations, ERCOT may only issue Dispatch Instructions for Direct Current Ties (DC Ties) to the appropriate Direct Current Tie Operator (DCTO), for Transmission Facilities to a Transmission Service Provider (TSP), for distribution facilities to a Distribution Service Provider (DSP), or for a Resource to the QSE that represents it.

(4) ERCOT shall post shift schedules on the MIS Secure Area.

6.5.2 Operating Standards

(1) ERCOT and each TSP shall operate the ERCOT Transmission Grid pursuant to NERC Reliability Standards, these Protocols, and Good Utility Practice. The requirements of the NERC Reliability Standards shall prevail to the extent there are any inconsistencies with these Protocols or Good Utility Practice. These Protocols control to the extent of any inconsistency between the Protocols and any of the following documents:

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT and each TSP and DCTO shall operate the ERCOT Transmission Grid pursuant to NERC Reliability Standards, these Protocols, and Good Utility Practice. The requirements of the NERC Reliability Standards shall prevail to the extent there

are any inconsistencies with these Protocols or Good Utility Practice. These Protocols control to the extent of any inconsistency between the Protocols and any of the following documents:

(a) The Operating Guides;

(b) ERCOT procedures manual for ERCOT Operators to use during normal and emergency operations of the ERCOT Transmission Grid;

(c) Specific operating procedures and RAPs submitted to ERCOT by individual Transmission Facilities owners or operators to address operating problems on their respective grids that could affect operation of the ERCOT Transmission Grid; and

(d) Guidelines established by the ERCOT Board, which may be more stringent than those established by NERC for the secure operation of the ERCOT Transmission Grid.

6.5.3 Equipment Operating Ratings and Limits

(1) ERCOT shall consider all equipment operating limits when issuing Dispatch Instructions. Except as stated in Section 6.5.9, Emergency Operations, if a Dispatch Instruction conflicts with a restriction that may be placed on equipment from time to time by a TSP, a DSP, or a Generation Resource’s QSE to protect the integrity of equipment, ERCOT shall honor the restriction.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) ERCOT shall consider all equipment operating limits when issuing Dispatch Instructions. Except as stated in Section 6.5.9, Emergency Operations, if a Dispatch Instruction conflicts with a restriction that may be placed on equipment from time to time by a TSP, a DSP, a DCTO, or a Generation Resource’s QSE to protect the integrity of equipment, ERCOT shall honor the restriction.

(2) Each TSP shall notify ERCOT of any limitations on the TSP’s system that may affect ERCOT Dispatch Instructions. ERCOT shall continuously maintain a posting on the

MIS Secure Area of any TSP limitations that may affect Dispatch Instructions. Examples of such limitations may include: temporary changes to transmission or transformer ratings, temporary changes to range of automatic tap position capabilities on auto-transformers, fixing or blocking tap changer, changes to no-load tap positions or other limitations affecting the delivery of energy across the ERCOT Transmission Grid. Any conflicts that cannot be satisfactorily resolved may be brought to ERCOT by any of the affected Entities for investigation and resolution.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) Each TSP or DCTO shall notify ERCOT of any limitations on the TSP's or DCTO's system that may affect ERCOT Dispatch Instructions. ERCOT shall continuously maintain a posting on the MIS Secure Area of any TSP or DCTO limitations that may affect Dispatch Instructions. Examples of such limitations may include: temporary changes to transmission or transformer ratings, temporary changes to range of automatic tap position capabilities on auto-transformers, fixing or blocking tap changer, changes to no-load tap positions or other limitations affecting the delivery of energy across the ERCOT Transmission Grid. Any conflicts that cannot be satisfactorily resolved may be brought to ERCOT by any of the affected Entities for investigation and resolution.

6.5.4 Inadvertent Energy Account

(1) ERCOT shall track any differences between the scheduled energy and the actual metered value at each Direct Current Tie (DC Tie) in an "Inadvertent Energy Account" between ERCOT and each interconnected non-ERCOT Control Area. ERCOT shall coordinate operation of each DC Tie with the DC Tie operator such that the Inadvertent Energy Account is maintained as close to zero as possible. Corrections of inadvertent energy between ERCOT and the other NERC-interconnected non-ERCOT Control Areas must comply with the NERC scheduling protocols and the ERCOT Operating Guides. ERCOT shall establish procedures to correct Inadvertent Energy Accounts with non-ERCOT Control Areas that are not subject to NERC scheduling protocols.

6.5.5 QSE Activities

(1) QSE activities during Real-Time operations are summarized in the table located in Section 6.3.2, Activities for Real-Time Operations. That table is intended to be only a

general guide and not controlling language, and any conflict between the table and another section of the Protocols is controlled by the other section.

6.5.5.1 Changes in Resource Status

(1) Each QSE shall notify ERCOT of a change in Resource Status via telemetry and through changes in the Current Operating Plan (COP) as soon as practicable following the change.

[NPRR1085: Replace paragraph (1) above with the following upon system implementation:]

(1) Each QSE shall notify ERCOT via telemetry of a change in Resource Status that is not related to a Forced Outage as soon as practicable but no longer than 15 minutes after the change in status occurs and through changes in the Current Operating Plan (COP) as soon as practicable but no longer than 60 minutes after the change in status of the Resource occurs.

[NPRR1085: Insert paragraph (2) below upon system implementation and renumber accordingly:]

(2) When an On-Line Resource is experiencing an event that may affect its availability and/or capability and that requires further actions to stabilize the Resource and/or determine the impact of the event, the QSE may change the Resource Status to ONHOLD within 15 minutes of experiencing an event. Following this Resource Status change, the telemetered HSL and any other applicable telemetry of the Resource as specified in paragraph (2) of Section 6.5.5.2, Operational Data Requirements, shall be updated as soon as practicable but no longer than 15 minutes after the change in Resource Status to ONHOLD. After the QSE has determined the impact of the event, the QSE shall change the Resource Status to its updated status as soon as practicable but no longer than 60 consecutive minutes of being in the ONHOLD status.

(2) Each QSE shall promptly inform ERCOT when the operating mode of its Generation Resource's Automatic Voltage Regulator (AVR) or Power System Stabilizer (PSS) is changed while the Resource is On-Line. The QSE shall also provide the Resource's AVR or PSS status logs to ERCOT upon request.

(3) Each QSE shall immediately report to ERCOT and the TSP any inability of the QSE's Generation Resource required to meet its reactive capability requirements in these Protocols.

[NPRR1085: Insert paragraph (5) below upon system implementation and renumber accordingly:]

(5) Each QSE shall timely update the telemetered Resource Status unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating the telemetered Resource Status only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the telemetered Resource Status begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

(4) A QSE or Resource Entity may use a Generation Resource or ESR to serve Customer Load as part of a Private Microgrid Island (PMI) in any circumstance in which the Customer Load and the Resource are both disconnected from the ERCOT System due to an Outage of the transmission and/or distribution system, provided that the configuration complies with the requirements of paragraph (7) of Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and provided that the QSE or Resource Entity has notified the Transmission and/or Distribution Service Provider (TDSP) of the establishment of a PMI configuration. The QSE shall ensure that the Load served by the Resource in the PMI configuration is de-energized at the time it is reconnected to the ERCOT System following the PMI configuration. All operations in a PMI configuration and any reconnection of Load following a PMI configuration shall be coordinated with the TDSP.

(5) A TDSP shall not intentionally disconnect, or direct another TDSP to disconnect, a Generation Resource or ESR included in a PMI configuration from the ERCOT System except in the following circumstances:

(a) An approved or accepted Planned or Maintenance Outage of a Transmission Facility reasonably requires, or would otherwise result in, the disconnection of the Resource from the ERCOT System;

(b) The Resource is a Distribution Generation Resource or Distribution Energy Storage Resource (DESR), and disconnection of the Resource is required for Distribution System maintenance;

(c) The TDSP's disconnection of the Resource is necessary to maintain the security of the TDSP's system or the ERCOT System;

(d) The TDSP's disconnection of the Resource is necessary to protect the public from a safety risk attributable to the operation of the Resource; or

(e) ERCOT directs the disconnection of the Resource.

6.5.5.2 Operational Data Requirements

(1) ERCOT shall use Operating Period data to monitor and control the reliability of the ERCOT Transmission Grid and shall use it in network analysis software to predict the short-term reliability of the ERCOT Transmission Grid. Each TSP, at its own expense, may obtain that Operating Period data from ERCOT or directly from QSEs.

(2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP's or DSP's expense, including:

(a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), determination of the High Ancillary Service Limit (HASL), High Dispatch Limit (HDL), Low Dispatch Limit (LDL) and Low Ancillary Service Limit (LASL), and is consistent with telemetered HSL, LSL and Non-Frequency Responsive Capacity (NFRC);

(b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) Generation Resource breaker and switch status;

(i) HSL (Combined Cycle Generation Resources) shall:

(i) Submit the HSL of the current operating configuration; and

(ii) When providing RRS, update the HSL as needed, to be consistent with Resource performance limitations of RRS provision;

(j) NFRC currently available (unloaded) and included in the HSL of the Combined Cycle Generation Resource's current configuration;

(k) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(l) Low Emergency Limit (LEL), under Section 6.5.9.2;

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

(o) Ancillary Service Schedule for each quantity of RRS and Non-Spin which is equal to the Ancillary Service Resource Responsibility minus the amount of Ancillary Service deployment;

(i) For On-line Non-Spin, Ancillary Service Schedule shall be set to zero;

(ii) For Off-Line Non-Spin and for On-Line Non-Spin using Off-Line power augmentation technology the Ancillary Service Schedule shall equal the Non-Spin obligation and then shall be set to zero within 20 minutes following Non-Spin deployment;

(p) Ancillary Service Resource Responsibility for each quantity of Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), RRS and Non-Spin. The sum of Ancillary Service Resource Responsibility for all Resources in a QSE is equal to the Ancillary Service Supply Responsibility for that QSE;

(q) Reg-Up and Reg-Down participation factors represent how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified Resource(s). The Reg-Up and Reg-Down participation factors for a Resource providing Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) shall be zero; and

(r) The designated Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources shall provide Real-Time telemetry for items (a), (b), (c), (d), (e), (g), and (h) above, PSS and AVR status for the total Generation Resource in addition to the Split Generation Resource the Master QSE represents.

[NPRR863, NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR863,

NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP's or DSP's expense, including:

(a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), High Dispatch Limit (HDL), and Low Dispatch Limit (LDL), and is consistent with telemetered HSL, LSL, and Frequency Responsive Capacity (FRC);

(b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) Generation Resource breaker and switch status;

(i) HSL (Combined Cycle Generation Resources) shall:

(i) Submit the HSL of the current operating configuration; and

(ii) When providing ECRS, update the HSL as needed, to be consistent with Resource performance limitations of ECRS provision;

(j) For Resources with capacity that is not capable of providing Primary Frequency Response (PFR), the current FRC of the Resource;

(k) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(l) Low Emergency Limit (LEL), under Section 6.5.9.2;

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

(o) For Resources with capacity that is not capable of providing PFR, the high and low limits in MW of the Resource's capacity that is frequency responsive;

(p) For RRS, including any sub-categories of RRS, the physical capability (in MW) of the Resource to provide RRS;

(q) For Ancillary Services other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the physical capability of the Resource to provide that specific type of Ancillary Service;

(r) Five-minute blended Normal Ramp Rates (up and down);

(s) The designated Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources shall provide Real-Time telemetry for items (a), (b), (c), (d), (e), (g), and (h) above, PSS and AVR status for the total Generation Resource in addition to the Split Generation Resource the Master QSE represents; and

(t) The telemetered MW of power augmentation capacity that is not On-Line for Resources that have power augmentation capacity included in HSL.

(3) For each Intermittent Renewable Resource (IRR), the QSE shall set the HSL equal to the current net output capability of the facility. The net output capability should consider the net real power of the IRR generation equipment, IRR generation equipment availability, weather conditions, and whether the IRR net output is being affected by compliance with a SCED Dispatch Instruction.

(4) For each Aggregate Generation Resource (AGR), the QSE shall telemeter the number of its generators online.

(5) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource's host TSP or DSP at the TSP's or DSP's expense. The Load Resource's net

real power consumption, Low Power Consumption (LPC) and Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a positive (+) sign convention:

(a) Load Resource net real power consumption (in MW);

(b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(c) Load Resource breaker status, if applicable;

(d) LPC (in MW);

(e) MPC (in MW);

(f) Ancillary Service Schedule (in MW) for each quantity of RRS and Non-Spin, which is equal to the Ancillary Service Resource Responsibility minus the amount of Ancillary Service deployment;

(g) Ancillary Service Resource Responsibility (in MW) for each quantity of Reg-Up and Reg-Down for Controllable Load Resources, and RRS and Non-Spin for all Load Resources;

(h) The status of the high-set under-frequency relay, if required for qualification. The under-frequency relay for a Load Resource providing Non-Spin shall be disabled and the status of that relay shall indicate it as disabled or unarmed;

(i) For a Controllable Load Resource providing Non-Spin, the Scheduled Power Consumption that represents zero Ancillary Service deployments;

(j) For a single-site Controllable Load Resource with registered maximum Demand response capacity of ten MW or greater, net Reactive Power (in MVAr);

(k) Resource Status (Resource Status shall be ONRL if high-set under-frequency relay is active);

(l) Reg-Up and Reg-Down participation factor, which represents how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified Resource(s). The Reg-Up and Reg-Down participation factors for a Resource providing FRRS-Up or FRRS-Down shall be zero; and

(m) For a Controllable Load Resource providing Non-Spin, the “Scheduled Power Consumption Plus Two Hours,” representing the QSE’s forecast of the Controllable Load Resource’s instantaneous power consumption for a point two hours in the future.

[NPRR863, NPRR1010, NPRR1029, and NPRR1131: Replace applicable portions of paragraph (5) above with the following upon system implementation for NPRR863, NPRR1029, or NPRR1131; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(5) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource's host TSP or DSP at the TSP's or DSP's expense. The Load Resource's net real power consumption, Low Power Consumption (LPC) and Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a positive (+) sign convention:

(a) Load Resource net real power consumption (in MW);

(b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(c) Load Resource breaker status, if applicable;

(d) LPC (in MW);

(e) MPC (in MW);

(f) The Load Resource's Ancillary Service self-provision (in MW) for RRS and/or ECRS provided via under-frequency relay;

(g) The status of the high-set under-frequency relay, if required for qualification. The under-frequency relay for a Load Resource providing Non-Spin shall be disabled and the status of that relay shall indicate it as disabled or unarmed;

(h) For a Controllable Load Resource providing Non-Spin, the Scheduled Power Consumption that represents zero Ancillary Service deployments;

(i) For a single-site Controllable Load Resource with registered maximum Demand response capacity of ten MW or greater, net Reactive Power (in MVAr);

(j) Resource Status;

(k) For an Aggregate Load Resource (ALR) providing Non-Spin, the "Scheduled Power Consumption Plus Two Hours," representing the QSE's forecast of the Controllable Load Resource's instantaneous power consumption for a point two hours in the future;

(l) For RRS, including any sub-categories of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(m) For Ancillary Service products other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the current physical capability of the Resource's ability to provide a particular Ancillary Service product; and

(n) For a Controllable Load Resource, 5-minute blended Normal Ramp Rates (up and down).

[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (6) below upon system implementation and renumber accordingly:]

(6) A QSE representing an ESR connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each ESR. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP's or DSP's expense, including:

(a) Net real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation or consumption of an ESR for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), in determination of High Dispatch Limit (HDL), and Low Dispatch Limit (LDL) and is consistent with telemetered HSL, LSL and Frequency Responsive Capacity (FRC);

(b) Gross real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) ESR breaker and switch status;

(i) HSL;

(j) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(k) Low Emergency Limit (LEL), under Section 6.5.9.2;

(l) LSL;

(m) For RRS, including any sub-category of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(n) For Ancillary Services other than RRS, a blended ramp rate (in MW/min) that reflects the current physical capability of the Resource to provide that specific type of Ancillary Service; and

(o) Five-minute blended normal up and down ramp rates;

(6) A QSE with Resources used in SCED shall provide communications equipment to receive ERCOT-telemetered control deployments.

(7) A QSE providing any Regulation Service shall provide telemetry indicating the appropriate status of Resources providing Reg-Up or Reg-Down, including status indicating whether the Resource is temporarily blocked from receiving Reg-Up and/or Reg-Down deployments from the QSE. This temporary blocking will be indicated by the enabling of the Raise Block Status and/or Lower Block Status telemetry points.

(a) Raise Block Status and Lower Block Status are telemetry points used in transient unit conditions to communicate to ERCOT that a Resource's ability to adjust its output has been unexpectedly impaired.

(b) When one or both of the telemetry points are enabled for a Resource, ERCOT will cease using the regulation capacity assigned to that Resource for Ancillary Service deployment.

(c) This hiatus of deployment will not excuse the Resource's obligation to provide the Ancillary Services for which it has been committed.

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

(c) This hiatus of deployment will not excuse the Resource's obligation to provide the Ancillary Services for which it has been awarded.

(d) These telemetry points shall only be utilized during unforeseen transient unit conditions such as plant equipment failures. Raise Block Status and Lower Block Status shall only be enabled until the Resource operator has time to update the Resource limits and Ancillary Service telemetry to reflect the problem.

(e) The Resource limits and Ancillary Service telemetry shall be updated as soon as practicable. Raise Block Status and Lower Block Status will then be disabled.

(8) Real-Time data for reliability purposes must be accurate to within three percent. This telemetry may be provided from relaying accuracy instrumentation transformers.

(9) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT. The telemetered Resource Status for a Combined Cycle Generation Resource may only be assigned a Resource Status of OFFNS if no generation units within that Combined Cycle Generation Resource are On-Line.

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

(9) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT. The telemetered Resource Status for a Combined Cycle Generation Resource may only be assigned a Resource Status of OFF if no generation units within that Combined Cycle Generation Resource are On-Line.

(10) A QSE representing Combined Cycle Generation Resources shall provide ERCOT with the possible operating configurations for each power block with accompanying limits. Combined Cycle Train power augmentation methods may be included as part of one or more of the registered Combined Cycle Generation Resource configurations. Power augmentation methods may include:

(a) Combustion turbine inlet air cooling methods;

(b) Duct firing;

(c) Other ways of temporarily increasing the output of Combined Cycle Generation Resources; and

(d) For Qualifying Facilities (QFs), an LSL that represents the minimum energy available for Dispatch by SCED, in MW, from the Combined Cycle Generation Resource based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

(11) A QSE representing Generation Resources other than Combined Cycle Generation Resources may telemeter an NFRC value for their Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT's approval of the Generation Resource's NFRC quantity.

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (11) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

(11) A QSE representing a Generation Resource other than a Combined Cycle Generation Resource may provide FRC telemetry for the Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT's approval.

(12) A QSE representing an ESR shall provide the following Real-Time telemetry data to ERCOT for each ESR:

(a) Maximum Operating State of Charge, in MWh;

(b) Minimum Operating State of Charge, in MWh;

(c) State of Charge, in MWh;

(d) Maximum Operating Discharge Power Limit, in MW; and

(e) Maximum Operating Charge Power Limit, in MW.

(13) In accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, ERCOT shall make the data specified in paragraph (12) available to any requesting TSP or DSP at the requesting TSP's or DSP's expense.

[NPRR1077: Insert paragraphs (14)-(16) below upon system implementation:]

(14) Except as provided in paragraph (15) below, a QSE representing a Settlement Only Generator (SOG) shall provide ERCOT the following Real-Time telemetry:

(a) Net real power injection at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for each site with one or more SOGs;

(b) For any site with one or more ESSs that are registered as an SOG, net real power withdrawal at the POI or POCC;

(c) For each inverter at the site, gross real power output measured at the generator terminals for all SOGs that are located behind that inverter, separately aggregated by fuel type;

(d) For SOGs at the same site that are not located behind an inverter, gross real power output measured at the generator terminals for all SOGs, separately aggregated by fuel type;

(e) For any site with one or more ESSs registered as an SOG, for each inverter, gross real power withdrawal by all such ESSs that are located behind that inverter, as measured at the generator terminals; and

(f) Generator breaker status.

(15) A QSE is not required to provide telemetry for a Settlement Only Distribution Generator (SODG) if:

(a) The site that includes the SODG has not exported more than 10 MWh in any calendar year, exclusive of any energy exported during any Settlement Interval in which an ERCOT-declared Energy Emergency Alert (EEA) is in effect;

(b) The QSE or Resource Entity for the SODG has submitted a written request to ERCOT seeking an exemption from the telemetry requirements under this paragraph; and

(c) ERCOT has provided the QSE or Resource Entity written confirmation that the SODG is exempt from providing telemetry under this paragraph.

(16) If ERCOT determines that a site that includes an SODG has exported more than 10 MWh in a given calendar year, it shall notify the SODG’s QSE that the SODG is no longer eligible for the telemetry exemption. Within 90 days of receiving this notification, the QSE for the SODG shall comply with the telemetry requirements of paragraph (14) above.

[NPRR885: Insert paragraph (17) below upon system implementation:]

(17) A QSE representing a Must-Run Alternative (MRA) shall telemeter the MRA MW currently available (unloaded) and not included in the HSL.

[NPRR1029: Insert paragraph (18) below upon system implementation:]

(18) A QSE representing a DC-Coupled Resource shall provide the following Real-Time telemetry data in addition to that required for other ESRs:

(a) Gross AC MW production of the intermittent renewable generation component of the DC-Coupled Resource, which includes the portion of the intermittent renewable generation used to charge the ESS and/or serve auxiliary Load on the DC side of the inverter; and

(b) Gross AC MW capability of the intermittent renewable generation component of the DC-Coupled Resource, based on Real-Time conditions.

[NPRR995: Insert paragraph (19) below upon system implementation:]

(19) A QSE representing a Settlement Only Energy Storage System (SOESS) that elects to include the net generation and/or net withdrawals of the SOESS in the estimate of Real-Time Liability (RTL) shall provide ERCOT Real-Time telemetry of the net generation and/or net withdrawals of the SOESS.

6.5.6 TSP and DSP Responsibilities

(1) Each TSP shall notify ERCOT of any changes in status of Transmission Elements as provided in these Protocols and clarified in the ERCOT procedures.

(2) Each TSP shall as soon as practicable report to ERCOT any short-term inability to meet minimum TSP reactive requirements.

(3) Each DSP shall as soon as practicable report to ERCOT any short-term inability to meet minimum DSP reactive requirements.

[NPRR1098: Replace Section 6.5.6 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (Southern Cross) provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a Transmission Service Provider (TSP) and the TSP gives ERCOT written notice that Southern Cross has provided

it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

6.5.6 TSP, TO, DCTO, and DSP Responsibilities

(1) Each TSP shall notify ERCOT of any changes in status of Transmission Elements as provided in these Protocols and clarified in the ERCOT procedures.

(2) Each TSP shall as soon as practicable report to ERCOT any short-term inability to meet minimum TSP reactive requirements.

(3) Each DSP shall as soon as practicable report to ERCOT any short-term inability to meet minimum DSP reactive requirements.

(4) Each DCTO shall immediately notify its designated TO of any change that affects the reactive capability of any DC Tie Facility it operates, including any change to the operation mode of the DC Tie Facility's voltage control system or any temporary transmission voltage limit changes. Each TO designated by a DCTO shall immediately notify ERCOT when a DC Tie Facility experiences a change that affects its reactive capability, including any change to the operation mode of the DC Tie Facility's voltage control system or any temporary transmission voltage limit changes.

(5) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support, shall for each such DC Tie provide to ERCOT, via ICCP, the status of the DC Tie Facility's voltage control system. An "On" status will indicate that the control system is on and set to regulate the voltage at the DC Tie's POIB in automatic voltage control mode, and an "Off" status will indicate that the control system is off or in manual mode.

(6) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Section 3.15.4 shall telemeter to ERCOT, via ICCP, the Real-Time target voltage at each DC Tie's POIB. Each TO shall modify the telemetered target voltage to match any verbal target voltage instruction issued as soon as practicable.

6.5.7 Energy Dispatch Methodology

(1) This Section outlines the programmatic and manual processes employed by ERCOT to simultaneously achieve power balance (minimizing the use of Regulation Service) and manage congestion while operating within the constraints of the system at economically optimized cost. The Real-Time Sequence describes the key system components and inputs that are required to support the SCED process, which produces the Locational Marginal Prices (LMPs) and Base Points while meeting transmission system constraints.

Section 6.5.7.3, Security Constrained Economic Dispatch, provides further details regarding additional components and inputs and ex-ante mitigation.

[NPRR1010: Replace Section 6.5.7 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.5.7 Real-Time Sequence Methodology

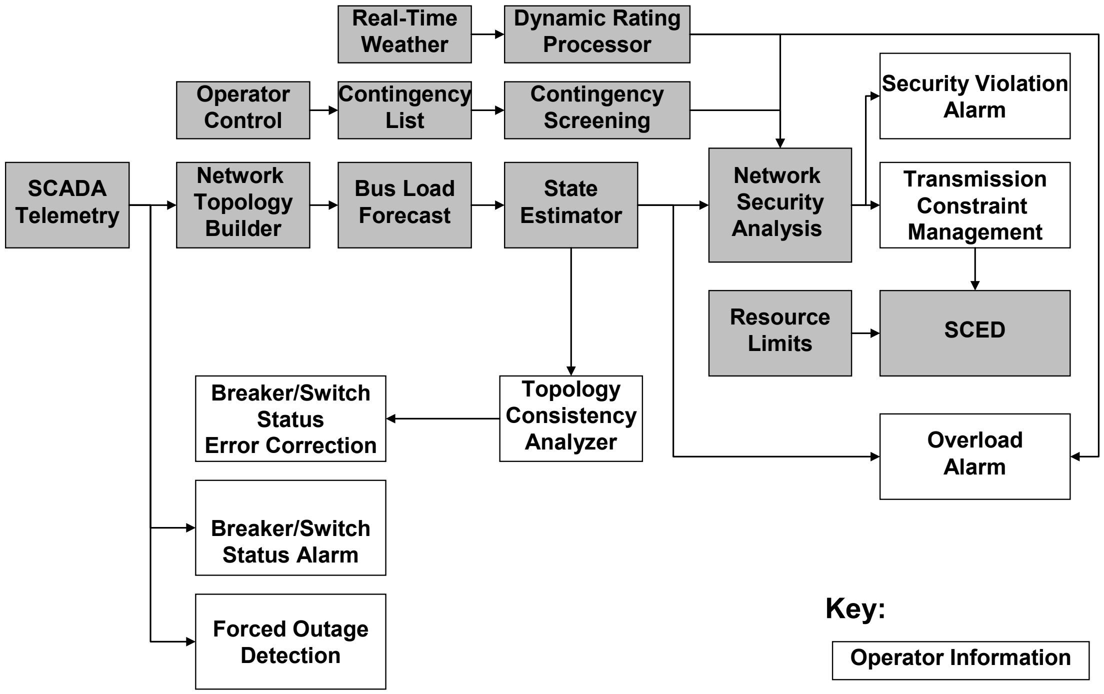
(1) This Section outlines the programmatic and manual processes employed by ERCOT to simultaneously achieve power balance (minimizing the use of Regulation Service), determine Ancillary Service awards, and manage congestion while operating within the constraints of the system at economically optimized cost. The Real-Time Sequence describes the key system components and inputs that are required to support the SCED process, which produces the Locational Marginal Prices (LMPs), Base Points, Real-Time MCPCs, and Ancillary Service awards while meeting transmission system constraints. Section 6.5.7.3, Security Constrained Economic Dispatch, provides further details regarding additional components and inputs and ex-ante mitigation.

6.5.7.1 Real-Time Sequence

(1) The Real-Time Sequence consists of multiple interdependent processes that are driven by telemetry data and the network topology. This Section describes the core aspects of the Real-Time Sequence.

(2) The figure below highlights the key computational modules and processes that are used during the Real-Time Sequence:

Real-Time Network Security Analysis



6.5.7.1.1 SCADA Telemetry

(1) SCADA telemetry provides the actual Real-Time status and output of Resources and the status of observable Transmission Elements of the Network Operations Model.

6.5.7.1.2 Network Topology Builder

(1) The Network Topology Builder creates the Updated Network Model based on the observed topology of the ERCOT Transmission Grid. The Updated Network Model is then used as the basis for the State Estimator solution.

6.5.7.1.3 Bus Load Forecast

(1) Once the Updated Network Model is created, the transmission Electrical Buses in the model will have a Bus Load Forecast applied. The forecasted Load must be denoted with a low State Estimator measurement confidence factor. The State Estimator must use the forecasted Load coupled with the remaining telemetry of line flows and voltages to estimate the actual Load on each Electrical Bus.

6.5.7.1.4 State Estimator

(1) The State Estimator must use the Bus Load Forecast and the remaining telemetry information of line flows and voltages to estimate all the transmission parameters needed to provide, on convergence, a mathematically consistent data set of constrained inputs to the Network Security Analysis (NSA) and the Topology Consistency Analyzer.

6.5.7.1.5 Topology Consistency Analyzer

(1) The Topology Consistency Analyzer identifies possibly erroneous breaker and switch status. The Topology Consistency Analyzer must notify ERCOT of inconsistencies detected and must indicate the correct breaker and switch status(es) when the preponderance of redundant information from the telemetered database indicates true errors in status. For example, such processing would detect flow on lines, flow on devices or network load, shown as disconnected from the transmission system and would indicate to ERCOT that there was a continuity error associated with the flow measurement or status indication. ERCOT may override SCADA telemetry as required to correct erroneous breaker and switch status before that information is processed by the NSA for the next SCED interval. ERCOT shall notify the TSP or QSE, who shall correct the status indications as soon as practicable. The Topology Consistency Analyzer maintains a summary of all incorrect status indicators and provides that information to all TSPs and other Market Participants through the MIS Secure Area.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) The Topology Consistency Analyzer identifies possibly erroneous breaker and switch status. The Topology Consistency Analyzer must notify ERCOT of inconsistencies detected and must indicate the correct breaker and switch status(es) when the preponderance of redundant information from the telemetered database indicates true errors in status. For example, such processing would detect flow on lines, flow on devices or network load, shown as disconnected from the transmission system and would indicate to ERCOT that there was a continuity error associated with the flow measurement or status indication. ERCOT may override SCADA telemetry as required to correct erroneous breaker and switch status before that information is processed by the NSA for the next SCED interval. ERCOT shall notify the TSP, DCTO, or QSE, who shall correct the status indications as soon as practicable. The Topology Consistency Analyzer maintains a summary of all incorrect status indicators

and provides that information to all TSPs, DCTOs, and other Market Participants through the MIS Secure Area.

6.5.7.1.6 Breakers/Switch Status Alarm Processor and Forced Outage Detection Processor

(1) The Real-Time Sequence includes processes that detect and provide alarms to the ERCOT Operator when the status of breakers and switches, Resources, transmission lines and transformers, and Load disconnected from the Updated Network Model changes. Also, the ERCOT Operator must be able to determine if an Outage of Transmission Facilities had been scheduled in the Outage Scheduler or is a Forced Outage.

6.5.7.1.7 Real-Time Weather and Dynamic Rating Processor

(1) The Dynamic Rating Processor provides Dynamic Ratings using the processes described in Section 3.10.8, Dynamic Ratings, for all transmission lines and transformer elements with Dynamic Ratings designated by the TSPs. ERCOT shall obtain Real-Time weather data, where available, from multiple locations and provide it to the Dynamic Rating Processor. Weather conditions must include ambient temperature and may include wind speed when available. ERCOT shall post summaries of dynamically adjusted Transmission Element limits on the MIS Secure Area in a form that allows Market Participants to directly upload Real-Time data into the Common Information Model (CIM).

(2) On a monthly basis, ERCOT shall provide a summary report for each dynamically rated Transmission Element specifying the average change in Normal Rating in MVA that is gained on the element through use of a Dynamic Rating rather than the Normal Rating. ERCOT shall post this report to the MIS Secure Area.

6.5.7.1.8 Overload Alarm Processor

(1) Once transmission line and transformer Dynamic Ratings are retrieved, ERCOT shall compare the actual flow and state estimated flow calculation of MVA to the effective Transmission Element limit and, if an out-of-limit condition exists, ERCOT shall produce an overload notification.

6.5.7.1.9 Contingency List and Contingency Screening

(1) For the Real-Time Sequence, ERCOT may select relevant contingencies from a standard contingency list previously developed by ERCOT under Section 5.5.1, Security

Sequence, that are likely to be active in Real-Time. ERCOT may use the information provided by the hour-ahead or Day-Ahead NSA to assist in determining which contingencies are candidates for activation.

6.5.7.1.10 Network Security Analysis Processor and Security Violation Alarm

(1) Using the input provided by the State Estimator, ERCOT shall use the NSA processor to perform analysis of all contingencies in the active list. For each contingency, ERCOT shall use the NSA processor to monitor the elements for limit violations. ERCOT shall use the NSA processor to verify Electrical Bus voltage limits to be within a percentage tolerance as outlined in the Operating Guides. Contingency security violations for transmission lines and transformers occur if:

(a) The predicted post-contingency MVA exceeds 100% of the Emergency Rating after consideration of Dynamic Ratings; and

(b) A RAP, AMP or RAS is not defined allowing relief within the time allowed by the security criteria as defined in Operating Guide Section 2.2.2, Security Criteria.

(2) When the NSA processor notifies ERCOT of a security violation, ERCOT shall immediately:

(a) Initiate the process described in Section 6.5.7.1.11, Transmission Network and Power Balance Constraint Management;

(b) Seek to determine what unforeseen change in system condition has arisen that has resulted in the security violation, especially those that were 125% or greater of the Emergency Rating for a single SCED interval or greater than 100% of the Emergency Rating for a duration of 30 minutes or more; and

(c) Where possible, seek to reverse the action (e.g. initiating a transmission clearance that the system was not properly pre-dispatched for) that has led to a security violation until further preventative action(s) can be taken.

(3) If SCED does not resolve a transmission security violation, ERCOT shall attempt to relieve the security violation by:

(a) Confirming that pre-determined RAPs are properly modeled in the system;

(b) Instructing Resources to follow Base Points from SCED if those Resources are not already doing so;

(c) Instructing Resources to update the Resources Status in the COP from ONTEST to ON in order to provide more capacity to SCED;

(d) Deploying Resource-Specific Non-Spin;

(e) Committing additional Generation Resources through the Reliability Unit Commitment (RUC) process;

(f) Removing conflicting non-cascading constraints from the SCED process;

(g) Re-Dispatching generation by over-riding HDLs and LDLs;

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

(g) Re-Dispatching generation or, in the case of an ESR, its output or consumption, by over-riding HDLs and LDLs;

(h) Instructing TSPs to utilize Reactive Power devices to manage voltage; and

(i) If all other mechanisms have failed, ERCOT may authorize the expedited use of a Temporary Outage Action Plan (TOAP) or Mitigation Plan.

(4) NSA must be capable of analyzing contingencies, including the effects of RASs, AMPs and RAPs modeled in the Network Operations Model. The NSA must fully integrate the evaluation and deployment of RASs, AMPs and RAPs and notify the ERCOT Operator of the application of these RASs, AMPs and RAPs to the solution.

(5) The Real-Time NSA may employ the use of appropriate ranking and other screening techniques to further reduce computation time by executing one or two iterations of the contingency study to gauge its impact and discard further study if the estimated result is inconsequential.

(6) HDL or LDL overrides required to pre-posture for an expected Outage shall only be utilized until SCED is capable of managing the related constraint by economic dispatch.

(7) ERCOT shall report monthly:

(a) All security violations that were 125% or greater of the Emergency Rating for a single SCED interval or greater than 100% of the Emergency Rating for a duration of 30 minutes or more during the prior reporting month and the number of occurrences and congestion cost associated with each of the constraints causing the security violations on a rolling 12 month basis.

(b) Operating conditions on the ERCOT System that contributed to each transmission security violation reported in paragraph (7)(a) above. Analysis should be made to understand the root cause and what steps could be taken to avoid a recurrence in the future.

6.5.7.1.11 Transmission Network and Power Balance Constraint Management

(1) ERCOT may not allow any constraint (contingency and limiting Transmission Element pair) identified by NSA to be activated in SCED until it has verified that the contingency definition in NSA associated with the constraint is accurate and appropriate given the current operating state of the ERCOT Transmission Grid. ERCOT shall continuously post to the MIS Secure Area all constraint contingencies in the NSA. ERCOT shall provide relevant constraint information, including, but not limited to, the contingency name as provided in the standard contingency list, whether or not the constraint is active in SCED, the overloaded Transmission Element name, the Rating of the overloaded Transmission Element including Generic Transmission Limits (GTLs) expressed in MW and MVA, and pre-contingency or post-contingency flows expressed in MW and MVA. For each Operating Day, ERCOT shall post to the MIS Secure Area within five days, a report listing all constraints with pre-contingency or post-contingency flows which exceeded the Rating of the overloaded Transmission Element for at least 15 minutes consecutively that were not activated in SCED and an explanation of why each constraint was not activated.

(2) ERCOT shall establish a maximum Shadow Price for each network constraint as part of the definition of contingencies. The cost calculated by SCED to resolve an additional MW of congestion on the network constraint is limited to the maximum Shadow Price for the network constraint.

(3) ERCOT shall establish a maximum Shadow Price for the power balance constraint. The cost calculated by SCED to resolve either the addition or reduction of one MW of dispatched generation on the power balance constraint is limited to the maximum Shadow Price for the power balance constraint.

(4) ERCOT shall determine the methodology for setting maximum Shadow Prices for network constraints and for the power balance constraint. Following review and recommendation by the Technical Advisory Committee (TAC), the ERCOT Board shall review the recommendation and approve a final methodology.

(5) The process for setting the maximum Shadow Prices as described above shall require ERCOT to obtain ERCOT Board approval of the values assigned to these caps along with the effective date for application of the cap. Within two Business Days following approval by the ERCOT Board, ERCOT shall post the Shadow Price caps and effective dates on the ERCOT website.

(6) If ERCOT determines that rating(s) in the Network Operations Model or configuration of the Transmission Facilities are not correct, then the TSP will provide the appropriate data submittals to ERCOT to correct the problem upon notification by ERCOT.

[NPRR857: Replace paragraph (6) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(6) If ERCOT determines that rating(s) in the Network Operations Model or configuration of the Transmission Facilities are not correct, then the TSP or DCTO will provide the appropriate data submittals to ERCOT to correct the problem upon notification by ERCOT.

6.5.7.1.12 Resource Limits

(1) The following Generation Resource limits are calculated by ERCOT and used as inputs by the SCED process:

(a) HASL;

(b) LASL;

(c) Normal Ramp Rate based on the values telemetered by the QSE to ERCOT;

(d) Emergency Ramp Rate based on the values telemetered by the QSE to ERCOT;

(e) SCED Up Ramp Rate (SURAMP), which represents the ability of a Generation Resource to increase generation output in SCED;

(f) SCED Down Ramp Rate (SDRAMP), which represents the ability of a Generation Resource to decrease generation output in SCED;

(g) HDL, which represents a dynamically calculated MW upper limit on a Resource that describes the maximum capability of the Resource SCED dispatch for the next five minutes (the Resource’s Real-Time generation plus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by HASL; and

(h) LDL, which represents a dynamically calculated MW lower limit on a Resource that describes the minimum capability of the Resource SCED dispatch for the next five minutes (the Resource’s Real-Time generation minus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by LASL.

(2) The following Load Resource limits are calculated by ERCOT and used in other calculations and as information for ERCOT Operators:

(a) For all Load Resources:

(i) HASL; and

(ii) LASL; and

(b) For Controllable Load Resources qualified to be Dispatched by SCED:

(i) Normal Ramp Rate based on the values telemetered by the QSE to ERCOT;

(ii) Emergency Ramp Rate based on the values telemetered by the QSE to ERCOT;

(iii) SURAMP, which represents the ability of a Load Resource to decrease consumption in SCED;

(iv) SDRAMP, which represents the ability of a Load Resource to increase consumption in SCED;

(v) HDL, which represents a dynamically calculated MW upper limit on a Resource that describes the maximum capability of the Resource SCED dispatch for the next five minutes (the Resource's Real-Time consumption plus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by HASL; and

(vi) LDL, which represents a dynamically calculated MW lower limit on a Resource that describes the minimum capability of the Resource SCED dispatch for the next five minutes (the Resource's Real-Time consumption minus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by LASL.

(3) For a more detailed explanation of all the Resource limits calculated by ERCOT, please reference Section 6.5.7.2, Resource Limit Calculator.

[NPRR1010 and NPRR1014: Replace applicable portions of Section 6.5.7.1.12 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]

6.5.7.1.12 Resource Limits

(1) The following Generation Resource or ESR limits are calculated by ERCOT and used as inputs by the SCED process:

(a) Normal Ramp Rate based on the values telemetered by the QSE to ERCOT, which represents the current ability of the Resource to follow a Base Point instruction;

(b) Emergency Ramp Rate based on the values telemetered by the QSE to ERCOT;

(c) HDL, which represents a dynamically calculated MW upper limit on a Resource that describes the maximum capability of the Resource's SCED dispatch and limits the amount of Reg-Up that can be awarded to the Resource for the next five minutes (the Resource's Real-Time generation or, in the case of an ESR, its Real-Time output or consumption, plus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by HSL; and

(d) LDL, which represents a dynamically calculated MW lower limit on a Resource that describes the minimum capability of the Resource's SCED dispatch and limits the amount of Reg-Down that can be awarded to the Resource for the next five minutes (the Resource's Real-Time generation or, in the case of an ESR, its Real-Time output or consumption, minus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by LSL.

(2) The following Load Resource limits are calculated by ERCOT for Controllable Load Resources qualified to be dispatched by SCED and used in other calculations and as information for ERCOT Operators:

(a) Normal Ramp Rate based on the values telemetered by the QSE to ERCOT, which represents the current ability of the Resource to follow a SCED Base Point instruction;

(b) Emergency Ramp Rate based on the values telemetered by the QSE to ERCOT;

(c) HDL, which represents a dynamically calculated MW upper limit on a Resource that describes the maximum capability of the Resource SCED dispatch and limits the amount of Reg-Down that can be awarded to the Resource for the next five minutes (the Resource's Real-Time consumption plus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by HSL; and

(d) LDL, which represents a dynamically calculated MW lower limit on a Resource that describes the minimum capability of the Resource SCED dispatch and limits the amount of Reg-Up that can be awarded to the Resource for the next five minutes (the Resource's Real-Time consumption minus the product of the Normal Ramp Rate, as telemetered by the QSE, multiplied by five), restricted by LSL.

(3) For a more detailed explanation of all the Resource limits calculated by ERCOT, please reference Section 6.5.7.2, Resource Limit Calculator.

6.5.7.1.13 Data Inputs and Outputs for the Real-Time Sequence and SCED

(1) Inputs: The following information must be provided as inputs to the Real-Time Sequence and SCED. ERCOT may require additional information as required, including:

(a) Real-Time data from TSPs including status indication for each point if that data element is stale for more than 20 seconds;

[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(a) Real-Time data from TSPs and DCTOs including status indication for each point if that data element is stale for more than 20 seconds;

(i) Transmission Electrical Bus voltages;

(ii) MW and MVAr pairs for all transmission lines, transformers, and reactors;

(iii) Actual breaker and switch status for all modeled devices; and

(iv) Tap position for auto-transformers;

(b) State Estimator results (MW and MVAr pairs and calculated MVA) for all modeled Transmission Elements;

(c) Transmission Element ratings from TSPs;

[NPRR857: Replace paragraph (c) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(c) Transmission Element ratings from TSPs and DCTOs;

(i) Data from the Network Operations Model:

(A) Transmission lines – Normal, Emergency, and 15-Minute Ratings (MVA); and

(B) Transformers and Auto-transformers – Normal, Emergency, and 15-Minute Ratings (MVA) and tap position limits;

(ii) Data from QSEs:

(A) Generator Step-Up (GSU) transformers tap position;

(B) Resource HSL (from telemetry); and

(C) Resource LSL (from telemetry); and

(d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

[NPRR857: Replace paragraph (d) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs, DCTOs, or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

(2) ERCOT shall validate the inputs of the Resource Limit Calculator as follows:

(a) The calculated SURAMP and SDRAMP are each greater than or equal to zero; and

(b) Other provision specified under Section 3.18, Resource Limits in Providing Ancillary Service.

[NPRR1010: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(3) Outputs for ERCOT Operator information and possible action include:

(a) Operator notification of any change in status of any breaker or switch;

(b) Lists of all breakers and switches not in their normal position;

(c) Operator notification of all Transmission Element overloads detected from telemetered or State-Estimated data;

(d) Operator notification of all Transmission Element security violations; and

(e) Operator summary displays:

(i) Transmission system status changes;

(ii) Overloads;

(iii) System security violations; and

(iv) Base Points.

(4) Every hour, ERCOT shall post on the MIS Secure Area the following information:

(a) Status of all breakers and switches used in the NSA except breakers and switches connecting Resources to the ERCOT Transmission Grid;

(b) All binding transmission constraints and the contingency or overloaded element pairs that caused such constraint; and

(c) Shift Factors, including Private Use Network Settlement Points, by Resource Node, Hub, Load Zone, and DC Tie.

(5) Sixty days after the applicable Operating Day, ERCOT shall post on the MIS Secure Area, the following information:

(a) Hourly transmission line flows and voltages from the State Estimator, excluding transmission line flows and voltages for Private Use Networks; and

(b) Hourly transformer flows, voltages and tap positions from the State Estimator, excluding transformer flows, voltages, and tap positions for Private Use Networks.

(6) Notwithstanding paragraph (5) above, ERCOT, in its sole discretion, shall release relevant State Estimator data less than 60 days after the Operating Day if it determines

the release is necessary to provide complete and timely explanation and analysis of unexpected market operations and results or system events including, but not limited to, pricing anomalies, recurring transmission congestion, and system disturbances. ERCOT's release of data under this paragraph shall be limited to intervals associated with the unexpected market or system event as determined by ERCOT. The data release shall be made available simultaneously to all Market Participants.

(7) Every hour, ERCOT shall post on the ERCOT website, the sum of ERCOT generation, and flow on the DC Ties, all from the State Estimator.

(8) After every SCED run, ERCOT shall post to the ERCOT website the sum of the HDL and the sum of the LDL for all Generation Resources On-Line and Dispatched by SCED.

(9) Sixty days after the applicable Operating Day, ERCOT shall post to the ERCOT website the summary LDL and HDL report from paragraph (8) above and include instances of manual overrides of HDL or LDL, including the name of the Generation Resource and the type of override.

(10) No sooner than sixty days after the applicable Operating Day, ERCOT shall provide to the appropriate TAC subcommittee instances of manual overrides of HDL or LDL, including the name of the Generation Resource, the reason for the override, and, as applicable, the cost as calculated in Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Payment.

(11) After every SCED run, ERCOT shall post to the MIS Certified Area, for any QSE, instances of a manual override of the HDL or LDL for a Generation Resource, including the original and overridden HDL or LDL.

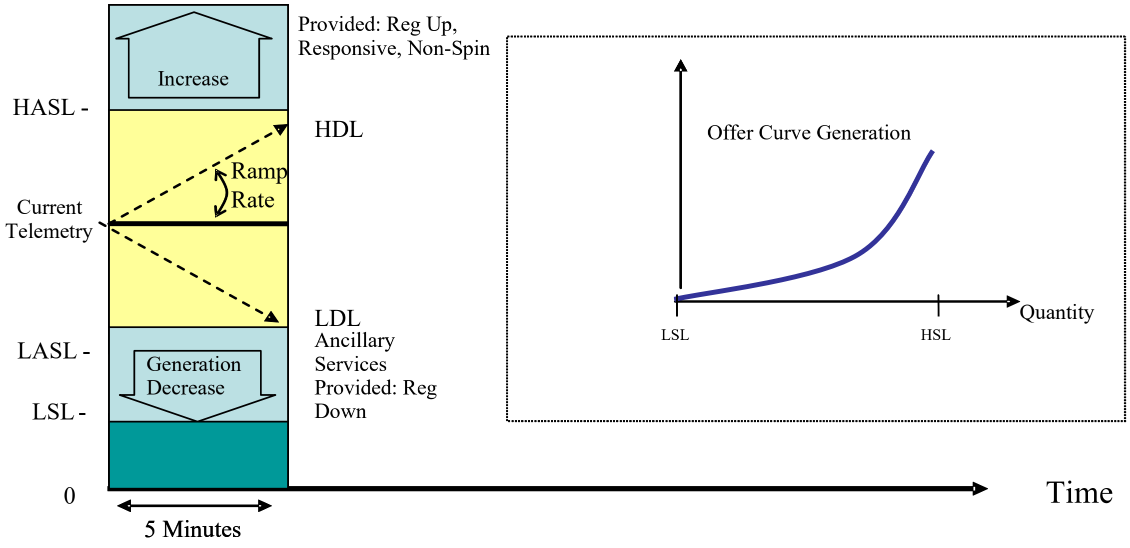
6.5.7.2 Resource Limit Calculator

(1) ERCOT shall calculate the HASL, LASL, SURAMP, SDRAMP, HDL and LDL within four seconds after a change of the Resource-specific attributes provided as part of the QSE's SCADA telemetry under Section 6.5.5.2, Operational Data Requirements. The formulas described below define which Resource-specific attributes must be used to calculate each Resource limit. The Resource limits are used as inputs into both the SCED process and the Ancillary Service Capacity Monitor as described in Section 6.5.7.6, Load Frequency Control. These Resource limits help ensure that the deployments produced by the SCED and Load Frequency Control (LFC) processes will respect the commitment of a Resource to provide Ancillary Services as well as individual Resource physical limitations.

(2) The figures below illustrate how the Resource Limit Calculator determines the Resource limits for Generation and Load Resources:

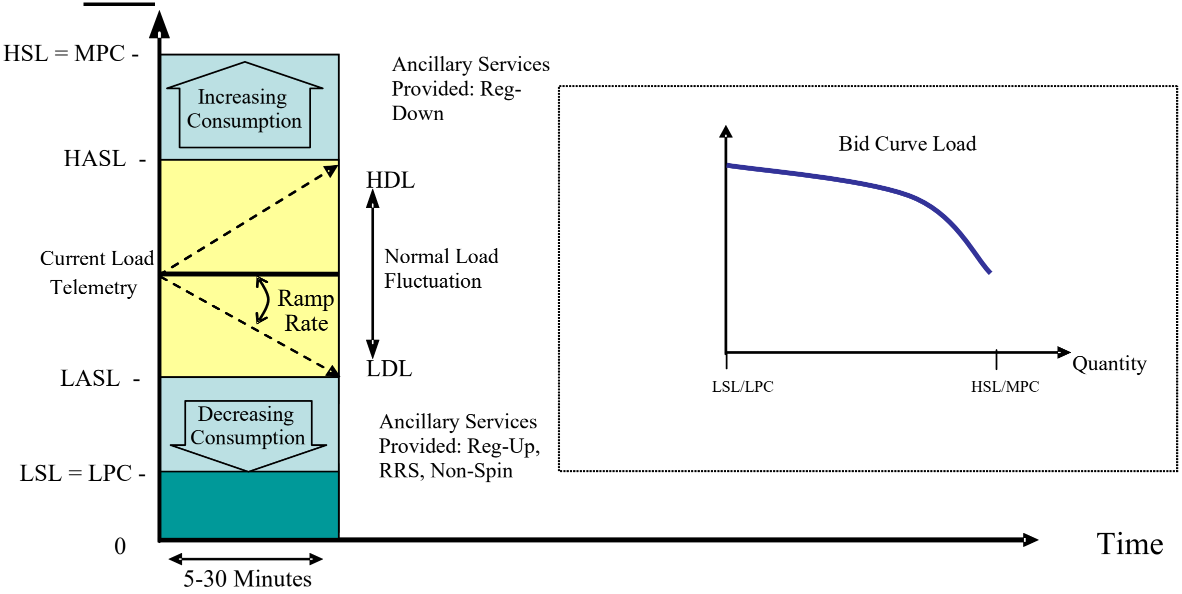
Generation Resources:

Generation



Load Resources:

Load



(3) For Generation Resources, HASL is calculated as follows:

$$\mathbf{HASL} = \mathbf{Max\ (LASL, (HSLTELEM - (RRSTELEM + RUSTELEM + NSRSTELEM + NFRCTELEM)))}$$

Variable	Description
HASL	High Ancillary Service Limit.
HSLTELEM	High Sustained Limit provided via telemetry – per Section 6.5.5.2.

LASL	Low Ancillary Service Limit.
RRSTELEM	RRS Ancillary Service Schedule provided by telemetry.
RUSTELEM	Reg-Up Ancillary Service Resource Responsibility designation provided by telemetry.
NSRSTELEM	Non-Spin Ancillary Service Schedule provided via telemetry.
NFRCTELEM	NFRC currently available (unloaded) and included in the HSL of the Generation Resource with non-zero RRS Ancillary Service Schedule telemetry.

(4) For Generation Resources, LASL is calculated as follows:

LASL = LSLTELEM + RDSTELEM

Variable	Description
LASL	Low Ancillary Service Limit.
LSLTELEM	Low Sustained Limit provided via telemetry.
RDSTELEM	Reg-Down Ancillary Service Resource Responsibility designation provided by telemetry.

(5) For each Generation Resource, the SURAMP is calculated as follows:

SURAMP = RAMPRATE – (1 – RDSDEPLP) * (RUSTELEM / 7)

Variable	Description
SURAMP	SCED Up Ramp Rate.
RAMPRATE	Normal Ramp Rate up, as telemetered by the QSE, when RRS is not deployed or when the subject Resource is not providing RRS. Emergency Ramp Rate up, as telemetered by the QSE, for Resources deploying RRS.
RUSTELEM	Reg-Up Ancillary Service Resource Responsibility designation provided by telemetry.
RDSDEPLP	Percentage of system-wide Reg-Down Ancillary Resource Responsibility deployed by LFC. This value shall not exceed 100% and controls the amount of ramp rate reserved for Regulation Service in Real-Time.

(6) For each Generation Resource, the SDRAMP is calculated as follows:

SDRAMP = NORMRAMP – (1 – RUSDEPLP) * (RDSTELEM / 7)

Variable	Description
SDRAMP	SCED Down Ramp Rate.
NORMRAMP	Normal Ramp Rate down, as telemetered by the QSE.

Variable	Description
RDSTELEM	Reg-Down Ancillary Service Resource Responsibility designation by Resource provided via telemetry.
RUSDEPLP	Percentage of system-wide Reg-Up Ancillary Resource Responsibility deployed by LFC. This value shall not exceed 100% and controls the amount of ramp rate reserved for Regulation Service in Real-Time.

(7) For Generation Resources, HDL is calculated as follows:

(a) If the telemetered Resource Status is SHUTDOWN, then

HDL = POWERTELEM – (SDRAMP * 5)

(b) If the telemetered Resource Status is any status code specified in item (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria, other than SHUTDOWN, then

HDL = Min (POWERTELEM + (SURAMP * 5), HASL)

Variable	Description
HDL	High Dispatch Limit.
POWERTELEM	Gross or net real power provided via telemetry.
SURAMP	SCED Up Ramp Rate.
SDRAMP	SCED Down Ramp Rate.
HASL	High Ancillary Service Limit – definition provided in Section 2, Definitions and Acronyms.

(8) For Generation Resources, LDL is calculated as follows:

(a) If the telemetered Resource Status is STARTUP, then

LDL = POWERTELEM + (SURAMP * 5)

(b) If the telemetered Resource Status is any status code specified in item (5)(b)(i) of Section 3.9.1 other than STARTUP, then

LDL = Max (POWERTELEM - (SDRAMP * 5), LASL)

Variable	Description
LDL	Low Dispatch Limit.
POWERTELEM	Gross or net real power provided via telemetry.
SDRAMP	SCED Down Ramp Rate.
LASL	Low Ancillary Service Limit – definition provided in Section 2.

(9) For Load Resources, HASL is calculated as follows:

HASL = Max (LPCTELEM, (MPCTELEM – RDSTELEM))

Variable	Description
HASL	High Ancillary Service Limit.
LPCTELEM	Low Power Consumption provided via telemetry.
MPCTELEM	Maximum Power Consumption provided via telemetry.
RDSTELEM	Reg-Down Ancillary Service Resource Responsibility designation provided by telemetry.

(10) For Load Resources, LASL is calculated as follows:

LASL = Min (HASL, (LPCTELEM + (RRSTELEM + RUSTELEM + NSRSTELEM)))

Variable	Description
LASL	Low Ancillary Service Limit.
HASL	High Ancillary Service Limit.
LPCTELEM	Low Power Consumption provided via telemetry.
RRSTELEM	RRS Ancillary Service Schedule provided by telemetry.
RUSTELEM	Reg-Up Ancillary Service Resource Responsibility designation provided by telemetry.
NSRSTELEM	Non-Spin Ancillary Service Schedule provided via telemetry.

(11) For each Load Resource, the SURAMP is calculated as follows:

SURAMP = RAMPRATE – (1 – RDSDEPLP) * (RUSTELEM / 7)

Variable	Description
SURAMP	SCED Up Ramp Rate.
RAMPRATE	Normal Ramp Rate up, as telemetered by the QSE, when RRS is not deployed or when the subject Load Resource is not providing RRS. Emergency Ramp Rate up, as telemetered by the QSE, for Load Resources deploying RRS.
RUSTELEM	Reg-Up Ancillary Service Resource Responsibility designation provided by telemetry.
RDSDEPLP	Percentage of system-wide Reg-Down Ancillary Resource Responsibility deployed by LFC. This value shall not exceed 100% and controls the amount of ramp rate reserved for Regulation Service in Real-Time.

(12) For each Load Resource, the SDRAMP is calculated as follows:

SDRAMP = NORMRAMP – (1 – RUSDEPLP) * (RDSTELEM / 7)

Variable	Description
SDRAMP	SCED Down Ramp Rate.
NORMRAMP	Normal Ramp Rate down, as telemetered by the QSE.

Variable	Description
RDSTELEM	Reg-Down Ancillary Service Resource Responsibility designation by Resource provided via telemetry.
RUSDEPLP	Percentage of system-wide Reg-Up Ancillary Resource Responsibility deployed by LFC. This value shall not exceed 100% and controls the amount of ramp rate reserved for Regulation Service in Real-Time.

(13) For Load Resources, HDL is calculated as follows:

HDL = Min (POWERTELEM + (SDRAMP * 5), HASL)

Variable	Description
HDL	High Dispatch Limit.
POWERTELEM	Net real power flow provided via telemetry.
SDRAMP	SCED Down Ramp Rate.
HASL	High Ancillary Service Limit – definition provided in Section 2.

(14) For Load Resources, LDL is calculated as follows:

LDL = Max (POWERTELEM - (SURAMP * 5), LASL)

Variable	Description
LDL	Low Dispatch Limit.
POWERTELEM	Net real power flow provided via telemetry.
SURAMP	SCED Up Ramp Rate.
LASL	Low Ancillary Service Limit – definition provided in Section 2.

[NPRR863, NPRR879, NPRR1010, and NPRR1014: Replace applicable portions of Section 6.5.7.2 above with the following upon system implementation for NPRR863, NPRR879, or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.2 Resource Limit Calculator

(1) ERCOT shall calculate the HDL and LDL within four seconds after a change of the Resource-specific attributes provided as part of the QSE's SCADA telemetry under Section 6.5.5.2, Operational Data Requirements. The formulas described below define which Resource-specific attributes must be used to calculate each Resource limit. The Resource limits are used as inputs into both the SCED process and the Ancillary Service Capacity Monitor as described in Section 6.5.7.6, Load Frequency Control. These Resource limits help ensure that the deployments produced by the SCED and Load Frequency Control (LFC) processes will respect individual Resource physical limitations.

(2) For SCED-dispatchable Generation Resources, HDL is calculated as follows:

(a) If the telemetered Resource Status is SHUTDOWN, then

HDL = POWERTELEM – (NORMRAMPDN * 5)

(b) If the telemetered Resource Status is any status code specified in item (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria, other than SHUTDOWN, then

HDL = Min (POWERTELEM + (NORMRAMPUP * 5), HSLTELEM)

Variable	Description
HDL	High Dispatch Limit.
POWERTELEM	Gross or net real power provided via telemetry.
NORMRAMPDN	5-minute blended Normal Ramp Rate down, as telemetered by the QSE.
NORMRAMPUP	5-minute blended Normal Ramp Rate up, as telemetered by the QSE.
HSLTELEM	For IRRs qualified to provide an Ancillary Service and telemetering a non-zero capability to provide that Ancillary Service, and all IRRs within an IRR Group where any IRR within the IRR Group is qualified to provide an Ancillary Service and telemetering a non-zero capability to provide that Ancillary Service, HSLTELEM shall be the five-minute intra-hour forecast for the Resource. For all other Resources, HSLTELEM shall be the Resource's HSL provided to ERCOT via telemetry, in accordance with Section 6.5.5.2.

(3) For SCED-dispatchable Generation Resources, LDL is calculated as follows:

(a) If the telemetered Resource Status is STARTUP, then

LDL = POWERTELEM + (NORMRAMPUP * 5)

(b) If the telemetered Resource Status is any status code specified in item (5)(b)(i) of Section 3.9.1 other than STARTUP, then

LDL = Max (POWERTELEM - (NORMRAMPDN * 5), LSLTELEM)

Variable	Description
LDL	Low Dispatch Limit.
POWERTELEM	Gross or net real power provided via telemetry.
LSLTELEM	Low Sustained Limit (LSL) provided via telemetry.
NORMRAMPDN	5-minute blended Normal Ramp Rate down, as telemetered by the QSE.
NORMRAMPUP	5-minute blended Normal Ramp Rate up, as telemetered by the QSE.

(4) For ESRs, HDL is calculated as follows:

(a) If the telemetered Resource Status is ONHOLD, then

HDL = 0

(b) If the telemetered Resource Status is ONTEST, then

HDL = **Max (Min (POWERTELEM, HSLTELEM), LSLTELEM)**

(c) If the telemetered Resource Status is any status code specified in item (5)(b)(iv) of Section 3.9.1, Current Operating Plan (COP) Criteria, other than OUT, EMR, EMRSWGR, ONHOLD, or ONTEST, then

HDL = Min (POWERTELEM + (NORMRAMPUP* 5), HSLTELEM)

Variable	**Description**
HDL	High Dispatch Limit.
POWERTELEM	Net real power provided via telemetry.
NORMRAMPUP	5-minute blended Normal Ramp Rate up, as telemetered by the QSE.
HSLTELEM	High Sustained Limit (HSL) provided via telemetry – per Section 6.5.5.2.

(5) For ESRs, LDL is calculated as follows:

(a) If the telemetered Resource Status is ONHOLD, then

LDL = 0

(b) If the telemetered Resource Status is ONTEST, then

LDL = **Max (Min (POWERTELEM, HSLTELEM), LSLTELEM)**

(c) If the telemetered Resource Status is any status code specified in item (5)(b)(iv) of Section 3.9.1, Current Operating Plan (COP) Criteria, other than OUT, or EMR, or EMRSWGR, or ONHOLD, or ONTEST, then

LDL = Max (POWERTELEM - (NORMRAMPDN * 5), LSLTELEM)

Variable	**Description**
LDL	Low Dispatch Limit.
POWERTELEM	Net real power provided via telemetry.
LSLTELEM	Low Sustained Limit provided via telemetry.
NORMRAMPDN	5-minute blended Normal Ramp Rate down, as telemetered by the QSE.

(6) For SCED-dispatchable Load Resources, HDL is calculated as follows:

HDL = Min (POWERTELEM + (NORMRAMPDN * 5), HSLTELEM)

Variable	Description
HDL	High Dispatch Limit.
POWERTELEM	Net real power flow provided via telemetry.
NORMRAMPDN	Normal Ramp Rate down, as telemetered by the QSE.
HSLTELEM	HSL provided via telemetry.

(7) For SCED-dispatchable Load Resources, LDL is calculated as follows:

LDL = Max (POWERTELEM - (NORMRAMPUP * 5), LSLTELEM)

Variable	Description
LDL	Low Dispatch Limit.
POWERTELEM	Net real power flow provided via telemetry.
NORMRAMPUP	Normal Ramp Rate up, as telemetered by the QSE.
LSLTELEM	LSL provided via telemetry.

6.5.7.3 Security Constrained Economic Dispatch

(1) The SCED process is designed to simultaneously manage energy, the system power balance and network congestion through Resource Base Points and calculation of LMPs every five minutes. The SCED process uses a two-step methodology that applies mitigation prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Output Schedules and Real-Time Market (RTM) Energy Bids to determine Resource Dispatch Instructions by maximizing bid-based revenues minus offer-based costs, subject to power balance and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP.

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

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

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

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

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

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

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

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

(b) DSRs with Energy Offer Curves

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

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

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

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

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

(d) IRRs

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

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

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

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

(e) RUC-committed Resources

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

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

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

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

Energy Offer Curve	Greater of $250 or the QSE submitted Energy Offer Curve
Zero	Greater of $250 or the first price point of the QSE submitted Energy Offer Curve

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

projected non-binding LMPs for Resource Nodes, Real-Time Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Hub LMPs and Load Zone LMPs on the ERCOT website pursuant to Section 6.3.2, Activities for Real-Time Operations.

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

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

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

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

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

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

6.5.7.3 Security Constrained Economic Dispatch

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

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

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

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

(a) Non-IRRs without Energy Offer Curves

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

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

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

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

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

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

(c) IRRs

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

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

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

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

(d) RUC-committed Resources

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

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

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

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

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

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

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

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

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

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

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

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

Zero	$4,500 or the effective VOLL, whichever is less

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

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

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

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

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

RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve)	Greater of: $4,500 or the effective VOLL, whichever is less; and the price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve for MW at and above HSL of QSE-committed configuration	Greater of: $4,500 or the effective VOLL, whichever is less; and the QSE-submitted Energy Offer Curve
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than $4,500)	$4,500 or the effective VOLL, whichever is less
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve)	Price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve for MW at and below HSL of QSE-committed configuration	The QSE-submitted Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-$250.00

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

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

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

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

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

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

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

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

(ii) For ECRS, the maximum of:

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

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

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

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

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

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

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

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

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

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

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

(e) For RUC-committed Resources:

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

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

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

(B) $250/MWh.

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

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

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

and, LSL is less than the lowest MW in submitted Energy Bid/Offer Curve		
LSL MW is less than zero, and, the lowest MW point on the Energy Bid/Offer Curve is greater than zero	From LSL to 0 MW From 0 MW to lowest MW point on submitted Energy Bid/Offer Curve	-$250.00 Price associated with the lowest MW in submitted Energy Bid/Offer Curve
LSL and the lowest MW point on the Energy Bid/Offer Curve are both less than or equal to zero, and, LSL is less than the lowest MW point on the Energy Bid/Offer Curve	From LSL to lowest MW point on submitted Energy Bid/Offer Curve	-$250.00

(b) At the time of SCED execution, if a valid Energy Bid/Offer Curve or Output Schedule does not exist for an ESR that has a status of On-Line, then ERCOT shall notify the QSE and create a proxy Energy Bid/Offer Curve priced at -$250/MWh for the MW portion of the curve less than zero MW, and priced at the RTSWCAP for the MW portion of the curve greater than zero MW.

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

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

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

MW	**Price (per MWh)**
LPC to MPC minus maximum MW of RTM Energy Bid	Price associated with the lowest MW in submitted RTM Energy Bid curve
MPC minus maximum MW of RTM Energy Bid to MPC	RTM Energy Bid curve

MPC	Right-most point (lowest price) on RTM Energy Bid curve

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

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

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

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

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

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

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

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

(i) Use Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT. Each Energy Offer Curve must be bounded at the lesser of the Reference LMP (from Step

1) or the appropriate Mitigated Offer Floor. In addition, each Energy Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource's Mitigated Offer Cap (MOC) curve at the LSL or the appropriate MOC;

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

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

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

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

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

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

(15) For each SCED process, in addition to the binding Base Points, Ancillary Service awards, Real-Time MCPCs, and LMPs, ERCOT shall calculate a non-binding projection of the Base Points, Ancillary Service awards, MCPCs, Resource Node LMPs, Real-Time Reliability Deployment Price Adders, Hub LMPs, and Load Zone LMPs at a frequency of every five minutes for at least 15 minutes into the future based

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

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

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

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

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

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

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

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

(d) Deployed ERS;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The above parameter is defined as follows:

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

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

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

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

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

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

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

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

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

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

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

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

6.5.7.3.1 Determination of Real-Time Reliability Deployment Price Adder

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

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (142) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

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

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

(d) Deployed ERS;

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

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

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

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

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

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

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

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

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

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

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

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

(i) Set the LSL and LDL to zero;

(ii) Remove all Ancillary Service Offers; and

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

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

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

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

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

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

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

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

(d) For all On-Line ESRs:

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

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

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

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

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

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

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

The above parameter is defined as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

6.5.7.4 Base Points

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

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

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

(c) Time of the Dispatch Instruction;

(d) Flag indicating SCED has dispatched a Generation Resource or Controllable Load Resource below HDL used by SCED;

[NPRR1111: Replace paragraph (d) above with the following upon system implementation of SCR819:]

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

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

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

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

(f) Other information relevant to that Dispatch Instruction.

[NPRR1010: Insert Section 6.5.7.4.1 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.5.7.4.1 Updated Desired Set Points

(1) Each Resource shall follow ERCOT-issued Updated Desired Set Points (UDSPs), unless otherwise instructed by ERCOT. ERCOT-issued UDSPs shall not include expected Primary Frequency Response.

(2) A UDSP is the sum of a calculated MW value representing the expected MW output of a Resource ramping to a SCED Base Point and the Resource-specific Regulation Service instruction from ERCOT.

(3) LFC shall send Resource-specific UDSP to QSEs every four seconds.

(4) Resources, excluding non-Controllable Load Resources, that have been awarded RRS as FFR-capable Resources or are telemetering a Resource Status of ONSC, will all have manual deployment instructions and expected deployments triggered automatically by frequency deviations included in the UDSP value provided to the QSE for the Resource. These deployment components of UDSP will reflect the latest Ancillary Service awards and are separate from the ramping component of UDSP.

(5) When ERCOT System frequency experiences a 0.05 Hz or greater deviation from scheduled frequency, and a Resource is ramping to a SCED Base Point in a manner directionally opposite to system frequency, the ramping component of the Resource's UDSP will be temporarily held constant and flagged accordingly.

6.5.7.5 Ancillary Services Capacity Monitor

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

(a) RRS capacity from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

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

(b) Ancillary Service Resource Responsibility for RRS from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

(iv) Resources capable of FFR;

(c) RRS deployed to Generation and Controllable Load Resources;

(d) Non-Spin available from:

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

(ii) Undeployed Load Resources;

(iii) Off-Line Generation Resources; and

(iv) Resources with Output Schedules;

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

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

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

(iii) Load Resources;

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

 (v) QSGRs;

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

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

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

(i) Available capacity:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

$$\textbf{PRC}_1 = \sum_{\substack{i=\textit{online}\\ \textit{generation}\\ \textit{resource}}}^{\substack{\textit{All online}\\ \textit{generation}\\ \textit{resources}}} \textbf{Min(Max((RDF*(HSL-NFRC) – Actual Net Telemetered Output)}_i\textbf{ , 0.0) , 0.2*RDF*(HSL-NFRC)}_i\textbf{),}$$

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

$$\textbf{PRC}_2 = \sum_{\substack{i=\textit{online}\\ \textit{WGR}}}^{\substack{\textit{All online}\\ \textit{WGRs}}} \textbf{Min(Max((RDF}_\textbf{W}\textbf{*HSL – Actual Net Telemetered Output)}_i\textbf{ , 0.0) , 0.2*RDF}_\textbf{W}\textbf{*HSL}_i\textbf{),}$$

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

$$\textbf{PRC}_3 = \sum_{\substack{i=\textit{online}\\ \textit{generation}\\ \textit{resource}}}^{\substack{\textit{All online}\\ \textit{generation}\\ \textit{resources}}} \textbf{((Hydro-synchronous condenser output)}_i\textbf{ as qualified by item (8) of Operating Guide Section 2.3.1.2, Additional Operational Details for Responsive Reserve Providers))}$$

$$\textbf{PRC}_4 = \sum_{\substack{i=\textit{online}\\ \textit{load}\\ \textit{resource}}}^{\substack{\textit{All online}\\ \textit{load}\\ \textit{resources}}} \textbf{(Min(Max((Actual Net Telemetered Consumption – LPC), 0.0), RRS Ancillary Service Resource Responsibility * 1.5) from all Load Resources controlled by high-set under frequency relays carrying RRS Ancillary Service Resource Responsibility)}_i$$

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

$$PRC_6 = \sum_{i=\text{online load resource}}^{\text{All online load resources}} \text{Min(Max((LRDF\_2 * Actual Net Telemetered Consumption – LPC)}_i\text{, 0.0), (0.2 * LRDF\_2 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED and not carrying Ancillary Service Resource Responsibility}$$

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

$$PRC_8 = \sum_{i=\text{online ESR}}^{\text{All online ESR}} \text{(If discharging or idle, Min(X\% of HSL based on droop, HSL-ESR-Gen “injection”, the capacity that can be sustained for 15 minutes per the State of Charge), else Min(X\% of (HSL – LSL(ESR “charging”) based on droop, the capacity that can be sustained for 15 minutes per the State of Charge – LSL(ESR “charging”)))}$$

Excludes ESR capacity used to provide FFR

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

The above variables are defined as follows:

Variable	Unit	Description
PRC_1	MW	Generation On-Line greater than 0 MW
PRC_2	MW	WGRs On-Line greater than 0 MW
PRC_3	MW	Hydro-synchronous condenser output

PRC_4	MW	Capacity from Load Resources controlled by high-set under-frequency relays carrying RRS Ancillary Service Resource Responsibility
PRC_5	MW	Capacity from Controllable Load Resources active in SCED and carrying Ancillary Service Resource Responsibility
PRC_6	MW	Capacity from Controllable Load Resources active in SCED and not carrying Ancillary Service Resource Responsibility
PRC_7	MW	Capacity from Resources capable of providing FFR
PRC_8	MW	ESR capacity capable of providing Primary Frequency Response
PRC	MW	Physical Responsive Capability
X	Percentage	Percent threshold based on the Governor droop setting of ESRs
RDF		The currently approved Reserve Discount Factor
RDF_W		The currently approved Reserve Discount Factor for WGRs
LRDF_1		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources carrying Ancillary Service Resource Responsibility
LRDF_2		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources not carrying Ancillary Service Resource Responsibility
NFRC	MW	Non-Frequency Responsive Capacity

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

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

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

[NPRR863, NPRR1010, NPRR1014, NPRR1029, and NPRR1085: Replace applicable portions of Section 6.5.7.5 above with the following upon system implementation for NPRR863, NPRR1014, NPRR1029, or NPRR1085; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.5 Ancillary Services Capacity Monitor

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

(a) RRS capability from:

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

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

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

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

(b) Ancillary Service Resource awards for RRS to:

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

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

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

(iv) Resources providing FFR;

(c) ECRS capability from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources;

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

(v) ESRs.

(d) Ancillary Service Resource awards for ECRS to:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources; and

(iii) Controllable Load Resources;

(iv) QSGRs; and

(v) ESRs.

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

(f) Non-Spin available from:

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

(ii) Undeployed Load Resources;

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

(iv) Resources with Output Schedules; and

(v) ESRs.

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

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

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

(iii) Load Resources;

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

(v) QSGRs; and

(vi) ESRs.

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

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

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

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

(l) Available capacity:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PRC_5 = $\sum_{i=\textit{online load resource}}^{\textit{All online load resources}}$ **Min(Max((LRDF_1*Actual Net Telemetered Consumption – LPC)$_i$, 0.0), (0.2 * LRDF_1 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED with an Ancillary Service Resource award**

PRC_6 = $\sum_{i=\textit{online load resource}}^{\textit{All online load resources}}$ **Min(Max((LRDF_2 * Actual Net Telemetered Consumption – LPC)$_i$, 0.0), (0.2 * LRDF_2 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED without an Ancillary Service Resource award**

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

PRC_8 = $\sum_{i=\text{online ESR}}^{\text{All online ESR}}$ **(If discharging or idle, Min(X% of HSL based on droop, HSL-ESR-Gen "injection", the capacity that can be sustained for 15 minutes per the State of Charge), else Min(X% of (HSL – LSL(ESR "charging") based on droop, the capacity that can be sustained for 15 minutes per the State of Charge – LSL(ESR "charging")))**

Excludes ESR capacity used to provide FFR

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

Excludes DC-Coupled Resource capacity used to provide FFR

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

The above variables are defined as follows:

Variable	**Unit**	**Description**
PRC_1	MW	Generation On-Line greater than 0 MW
PRC_2	MW	WGRs On-Line greater than 0 MW
PRC_3	MW	Synchronous condenser output
PRC_4	MW	Capacity from Load Resources with an ECRS Ancillary Service Resource award
PRC_5	MW	Capacity from Controllable Load Resources active in SCED with an Ancillary Service Resource award
PRC_6	MW	Capacity from Controllable Load Resources active in SCED without an Ancillary Service Resource award
PRC_7	MW	Capacity from Resources capable of providing FFR
PRC_8	MW	ESR capacity capable of providing Primary Frequency Response
PRC_9	MW	Capacity from DC-Coupled Resources capable of providing Primary Frequency Response

PRC	MW	Physical Responsive Capability
X	Percentage	Percent threshold based on the Governor droop setting of ESRs
RDF		The currently approved Reserve Discount Factor
RDF_W		The currently approved Reserve Discount Factor for WGRs
LRDF_1		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources awarded an Ancillary Service Resource award
LRDF_2		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources not awarded an Ancillary Service Resource award
FRCHL	MW	Telemetered High limit of the FRC for the Resource
FRCO	MW	Telemetered output of FRC portion of the Resource

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

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

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

6.5.7.6 Load Frequency Control

(1) The function of LFC is to maintain system frequency without a cost optimization function. ERCOT shall execute LFC every four seconds to reduce system frequency deviations from scheduled frequency by providing a control signal to each QSE that represents Resources providing Regulation Service and RRS service.

[NPRR863: Replace paragraph (1) above with the following upon system implementation:]

(1) The function of LFC is to maintain system frequency without a cost optimization function. ERCOT shall execute LFC every four seconds to reduce system frequency deviations from scheduled frequency by providing a control signal to each QSE that represents Resources providing Regulation Service, RRS, and ECRS.

6.5.7.6.1 LFC Process Description

(1) The LFC system corrects system frequency based on the Area Control Error (ACE) algorithm and Good Utility Practice.

(2) The ACE algorithm subtracts the actual frequency in Hz from the scheduled system frequency (normally 60 Hz), and multiplies the result by the frequency bias constant of MW/0.1 Hz. The ACE algorithm then takes that product and subtracts a configurable portion of the sum of the difference between the Updated Desired Base Point and Real-Time net MW output as appropriate. LFC shall ensure that the total reduction will not exceed the system-wide regulation requirement. This calculation produces an ACE value, which is a MW-equivalent correction needed to control the actual system frequency to the scheduled system frequency value.

(3) The LFC module receives inputs from Real-Time telemetry that includes Resource output and actual system frequency. The LFC uses actual Resource information calculated from SCADA to determine available Resource capacity providing Regulation and RRS services.

(4) Based on the ACE MW correction, the LFC issues a set of control signals every four seconds to each QSE providing Regulation and, if required, each QSE providing RRS. Control must be proportional to the QSE's share of each of the services that it is providing, respecting the QSE's Resources' capability to provide regulation control. Control signals are provided to the QSE using the ICCP data link. QSEs shall receive an Updated Desired Base Point updated every four seconds by LFC. ERCOT will provide an Operations Notice of any methodology change to the determination of the Updated Desired Base Point within 60 minutes of the change.

(5) Each QSE shall allocate its Regulation energy deployment among its Resources to meet a deployment signal, and shall provide ERCOT with the participation factor of each Resource via telemetry in accordance with Section 6.5.7.6.2.1, Deployment of Regulation Service, and Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency. A QSE may allocate Regulation Service Ancillary Service Resource Responsibility to any Resource telemetering a Resource Status of ONOPTOUT. Each QSE's allocation of Regulation Service to its Resources must be consistent with the telemetry provided under Section 6.5.5.2, Operational Data Requirements. Each QSE's allocation of its Regulation energy deployment among its Resources to meet a deployment signal must ensure the participation factors of all its Generation Resources in comparison to all its Controllable Load Resources remains constant.

[NPRR1092: Replace paragraph (5) above with the following upon system implementation:]

(5) Each QSE shall allocate its Regulation energy deployment among its Resources to meet a deployment signal, and shall provide ERCOT with the participation factor of each Resource via telemetry in accordance with Section 6.5.7.6.2.1, Deployment of Regulation Service, and Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency. A QSE may allocate Regulation Service Ancillary Service Resource Responsibility to any Resource that has successfully opted out of RUC Settlement. Each QSE's allocation of Regulation Service to its Resources must be consistent with the telemetry provided under Section 6.5.5.2, Operational Data Requirements. Each QSE's allocation of its Regulation energy deployment among its Resources to meet a

deployment signal must ensure the participation factors of all its Generation Resources in comparison to all its Controllable Load Resources remains constant.

(6) If all Reg-Up capacity has been deployed, ERCOT shall use the LFC system to deploy Responsive Reserve on Generation Resources and Controllable Load Resources. Such Responsive Reserve deployments by ERCOT must be deployed as specified in Section 6.5.7.6.2.2, Deployment of Responsive Reserve Service.

(7) ERCOT shall settle energy that results from LFC deployment at the Settlement Point Price for the point of injection. When a QSE deploys Responsive Reserve Service, the QSE shall deploy units consistent with the performance criteria for RRS service in Sections 8.1.1.3.2, Responsive Reserve Capacity Monitoring Criteria, and 8.1.1.4.2, Responsive Reserve Service Energy Deployment Criteria.

(8) The inputs for LFC include:

(a) Actual system frequency;

(b) Scheduled system frequency;

(c) Capacity available for Regulation by QSE;

(d) Telemetered high and low Regulation availability status indications for each Resource available for Regulation deployments for ERCOT information;

(e) Resource limits calculated by ERCOT as described Section 6.5.7.2, Resource Limit Calculator;

(f) Resource Regulation participation factor;

(g) Capacity available for RRS by QSE;

(h) ERCOT System frequency bias; and

(i) Telemetered Resource output.

(9) If system frequency deviation is greater than an established threshold, ERCOT may issue Dispatch Instructions to those Resources not providing Reg-Up or Reg-Down that have Base Points directionally opposite ACE, to temporarily suspend ramping to their Base Point until frequency deviation returns to zero.

[NPRR863 and NPRR1010: Replace applicable portions of Section 6.5.7.6.1 above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.6.1 LFC Process Description

(1) The LFC system corrects system frequency based on the Area Control Error (ACE) algorithm and Good Utility Practice.

(2) The ACE algorithm subtracts the actual frequency in Hz from the scheduled system frequency (normally 60 Hz), and multiplies the result by the frequency bias constant of MW/0.1 Hz. The ACE algorithm then takes that product and subtracts a configurable portion of the sum of the difference between the Updated Desired Set Point (UDSP) and Real-Time net MW output as appropriate. LFC shall ensure that the total reduction will not exceed the system-wide regulation requirement. This calculation produces an ACE value, which is a MW-equivalent correction needed to control the actual system frequency to the scheduled system frequency value.

(3) The LFC module receives inputs from Real-Time telemetry that includes Resource output and actual system frequency. The LFC uses actual Resource information calculated from SCADA to determine available Resource capacity providing Regulation Service, RRS, and ECRS.

(4) Based on the ACE MW correction, the LFC issues a set of control signals every four seconds for each Resource providing Regulation and, if required, each Resource providing RRS or ECRS. Control signals to each Resource are provided to the QSE using the ICCP data link. QSEs shall receive a UDSP updated every four seconds by LFC. ERCOT will provide an operations notice of any methodology change to the determination of the UDSP within 60 minutes of the change.

(5) If all Reg-Up capacity has been deployed, ERCOT shall run off-cycle SCED executions or use the LFC system to deploy ECRS on Resources providing FFR or with an ONSC Resource Status. Such ECRS deployments by ERCOT must be deployed as specified in Section 6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service.

(6) ERCOT shall settle energy that results from LFC deployment at the Settlement Point Price for the point of injection. When a QSE deploys RRS or ECRS, the QSE shall deploy units consistent with the performance criteria in Sections 8.1.1.3.2, Responsive Reserve Capacity Monitoring Criteria, Section 8.1.1.3.4, ERCOT Contingency Reserve Service Capacity Monitoring Criteria, 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria, and 8.1.1.4.4, ERCOT Contingency Reserve Service Energy Deployment Criteria.

(7) The inputs for LFC include:

(a) Actual system frequency;

(b) Scheduled system frequency;

(c) Capacity awarded for Regulation Service to Resources;

(d) For Resources awarded Regulation Service, telemetered HSL or MPC, and LSL or LPC;

(e) Resource limits calculated by ERCOT as described in Section 6.5.7.2, Resource Limit Calculator;

(f) Capacity awarded for RRS and ECRS to Resources;

(g) ERCOT System frequency bias; and

(h) Telemetered Resource output.

6.5.7.6.2 LFC Deployment

(1) ERCOT may deploy Regulation Service, RRS, and Non-Spin only as prescribed by their respective specific functions to maintain frequency and system security. ERCOT may not substitute one Ancillary Service for another.

[NPRR863: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT may deploy Regulation Service, RRS, ECRS, and Non-Spin only as prescribed by their respective specific functions to maintain frequency and system security. ERCOT may not substitute one Ancillary Service for another.

[NPRR1010: Insert paragraph (2) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) LFC will send UDSP deployment signals for each Resource, as specified in Section 6.5.7.4.1, Updated Desired Set Points.

6.5.7.6.2.1 Deployment of Regulation Service

(1) ERCOT shall deploy Reg-Up and Reg-Down necessary to maintain ERCOT System frequency to meet NERC Control Area and other Control Area performance criteria as specified in these Protocols and the Operating Guides.

(2) Reg-Up is a deployment or recall of a deployment referenced to the Resource's Base Point in response to a change (up or down) in ERCOT System frequency to maintain the

target ERCOT System frequency within predetermined limits according to the Operating Guides.

(3) Reg-Down is a deployment or recall of a deployment referenced to the Resource's Base Point in response to a change (up or down) in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

(4) These requirements also apply to the deployment or recall of a deployment of Reg-Up and Reg-Down:

(a) Deployment or recall of a deployment must be accomplished through use of an automatic signal from ERCOT to each QSE provider of Reg-Up and Reg-Down.

(b) ERCOT shall minimize Reg-Up and Reg-Down energy as much as practicable in each SCED cycle.

(c) ERCOT shall settle energy provided by Reg-Up and Reg-Down at the Resource's Settlement Point Price.

(d) ERCOT shall integrate the control signal sent to providers of Reg-Up and shall calculate the amount of energy deployed by Reg-Up in each Settlement Interval.

(e) ERCOT shall integrate the control signal sent to providers of Reg-Down and shall calculate the amount of energy deployed by Reg-Down in each Settlement Interval.

(f) ERCOT shall calculate for each LFC cycle the amount of regulation that each Resource is expected to provide at that instant in time. The expected amount must be averaged over each SCED interval. The actual generation from telemetry must also be averaged over each SCED interval.

(5) Every day, ERCOT shall post to the MIS Secure Area the total amount of deployed Reg-Up and Reg-Down energy in each Settlement Interval of the previous day.

(6) For each Resource providing Reg-Up or Reg-Down, the implied ramp rate in MW per minute is the total amount of Regulation Service awarded divided by five.

(7) Each QSE providing Reg-Up or Reg-Down and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring.

(8) ERCOT shall issue Reg-Up and Reg-Down deployment Dispatch Instructions over ICCP. Those Dispatch Instructions must contain the change in MW output requested of the QSE assuming all Resources are at their Updated Desired Base Point issued by LFC.

[NPRR1010: Replace paragraph (8) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(8) ERCOT shall issue Reg-Up and Reg-Down deployment Dispatch Instructions over ICCP. Those Dispatch Instructions must contain the change in MW output requested of the Resource.

(9) Reg-Up and Reg-Down Dispatch Instructions shall be included as a component of a Resource's UDSP.

(10) Upon the receipt of new Base Points and Ancillary Service awards from SCED, LFC will reset Regulation Service instructions to zero.

6.5.7.6.2.2 Deployment of Responsive Reserve (RRS)

(1) RRS is intended to:

(a) Help restore the frequency within the first few seconds of a significant frequency deviation of the interconnected transmission system;

(b) Provide energy during the implementation of an EEA; and

(c) Provide backup Reg-Up.

(2) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides, by one or more of the following:

(a) RRS energy deployment by automatic Governor response as a result of frequency deviation;

(b) Through use of an automatic Dispatch Instruction signal to deploy RRS capacity from Generation Resources providing Primary Frequency Response or Controllable Load Resources providing Primary Frequency Response;

(c) By Dispatch Instructions for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System; and

(d) RRS energy deployment by automatic action of high-set under-frequency relays as a result of a significant frequency deviation.

(3) ERCOT shall deploy RRS to respond to a frequency deviation when the power requirement to restore frequency to normal ACE in ten minutes exceeds the Reg-Up ramping capability. Deployment of RRS on Load Resources, excluding Controllable Load Resources, must be as described in Section 6.5.9.4, Energy Emergency Alert.

(4) ERCOT may deploy RRS in response to system disturbance requirements as specified in the Operating Guides if no additional energy is available to be dispatched from SCED as determined by the Ancillary Service Capacity Monitor.

(5) Energy from RRS Resources may also be deployed by ERCOT under Section 6.5.9, Emergency Operations.

(6) ERCOT shall allocate the deployment of RRS proportionally among QSEs that provide RRS using Resources that are not on high-set under-frequency relays.

(7) ERCOT shall use the SCED and Non-Spin as soon as practicable to minimize the prolonged use of RRS energy.

(8) Once RRS is deployed, the QSE’s obligation to deliver RRS remains in effect until specifically instructed by ERCOT to stop providing RRS. However, except in an Emergency Condition, the QSE’s obligation to deliver RRS may not exceed the period for which the service was committed.

(9) Following the deployment or recall of a deployment by Dispatch Instruction of RRS, QSE shall adjust the telemetered RRS Ancillary Service Schedule of Resources providing the service and ERCOT shall adjust the HASL and LASL based on the QSE’s telemetered Ancillary Service Schedule for RRS as described in Section 6.5.7.2, Resource Limit Calculator, to account for such deployment.

(10) QSEs providing RRS and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring.

(11) ERCOT shall issue RRS deployment Dispatch Instructions over ICCP for Generation Resources and Controllable Load Resources and Extensible Markup Language (XML) for all other Load Resources. Those Dispatch Instructions must contain the MW output requested. For Generation Resources and Controllable Load Resources from which RRS capacity was deployed, ERCOT shall use SCED to dispatch RRS energy. The Base Points for those Resources includes RRS energy as well as any other energy dispatched by SCED.

(12) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire responsibility or, if only partial deployment is possible, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(13) RRS provided from a Generation Resource shall be responsive to frequency deviations as defined in Section 8.5.1.1, Governor in Service. Generation Resources providing RRS must have a Governor droop setting that is not greater than 5.0%.

(14) RRS provided from a Resource capable of FFR shall self-deploy their obligated response within 15 cycles after frequency drops below 59.85 Hz and must continue to provide a response until the frequency increases above that level. Resources which require recharging may do so once the frequency increases above 59.990 Hz.

(15) RRS provided by interruptible Load shall have automatic under-frequency relay setting set at no lower than 59.70 Hz

(16) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides by one or more of the following:

(a) RRS energy deployment during an EEA;

(b) By Dispatch Instructions for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System; and

(c) RRS energy deployment from Load Resources and Generation Resources operating in synchronous condenser fast-response mode by automatic action of high-set under-frequency relays as a result of a significant frequency deviation.

[NPRR863 and NPRR1010: Replace applicable portions of Section 6.5.7.6.2.2 above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.6.2.2 Deployment of Responsive Reserve (RRS)

(1) RRS is intended to:

(a) Help restore the frequency within the first few seconds of a significant frequency deviation of the interconnected transmission system; and

(b) Provide energy during the implementation of an EEA.

(2) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides, by one or more of the following:

(a) RRS energy deployment by automatic Governor response as a result of frequency deviation;

(b) By Dispatch Instruction for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System;

(c) RRS energy deployment by automatic action of high-set under-frequency relays as a result of a significant frequency deviation; and

(d) By Dispatch Instruction for deployment of RRS from Resources with a Resource Status of ONSC or Resources providing FFR.

(3) ERCOT shall deploy RRS to respond to a frequency deviation when the power requirement to restore frequency to normal ACE in ten minutes exceeds the Reg-Up

ramping capability. Deployment of RRS on Load Resources, excluding Controllable Load Resources, must be as described in Section 6.5.9.4, Energy Emergency Alert.

(4) Energy from RRS Resources may also be deployed by ERCOT under Section 6.5.9, Emergency Operations.

(5) For Resources providing RRS with a Resource Status of ONSC, ERCOT shall deploy RRS as described in Section 6.5.9.4.2, EEA Levels, and Nodal Operating Guide Section 2.3.1.2, Additional Operational Details for Responsive Reserve Providers.

(6) For Resources providing RRS with FFR, ERCOT may manually deploy the FFR RRS in an attempt to recover frequency to meet NERC Performance Control Standards after utilizing Reg-Up and the SCED process which includes off-cycle SCED executions.

(7) ERCOT shall use the SCED, ECRS, and Non-Spin as soon as practicable to minimize the prolonged use of RRS energy.

(8) Once RRS is manually deployed on Load Resources controlled by under-frequency relays or Resources telemetering a Resource Status of ONSC, the Resource's obligation to deliver RRS remains in effect until recalled by ERCOT.

(9) Resources providing RRS and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring.

(10) ERCOT shall issue RRS deployment Dispatch Instructions over ICCP for Generation Resources awarded RRS with a Resource Status of ONSC, and SCED-dispatchable Resources providing FFR. Dispatch Instructions must contain the MW output requested. UDSPs for those Resources includes RRS energy deployments as well as any other energy dispatched by SCED.

(11) ERCOT shall issue RRS deployment Dispatch Instructions, specifying the required MW output, through Extensible Markup Language (XML) for non-Controllable Load Resources.

(12) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire award or, if only partial deployment is needed, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(13) RRS provided from a Generation Resource shall be responsive to frequency deviations as defined in Section 8.5.1.1, Governor in Service. Generation Resources providing RRS must have a Governor droop setting that is not greater than 5.0%.

(14) RRS provided from a Resource capable of FFR shall self-deploy their obligated response within 15 cycles after frequency drops below 59.85 Hz and must continue to

provide a response until the frequency increases above that level. Resources which require recharging may do so once the frequency increases above 59.990 Hz.

(15) RRS provided by interruptible Load shall have automatic under-frequency relay setting set at no lower than 59.70 Hz.

(16) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides by one or more of the following:

(a) RRS energy deployment during an EEA;

(b) By Dispatch Instructions for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System; and

(c) RRS energy deployment from Load Resources and Generation Resources operating in synchronous condenser fast-response mode by automatic action of high-set under-frequency relays as a result of a significant frequency deviation.

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

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

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

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

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

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

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

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

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

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

(6) Subject to the exceptions described in paragraphs (a) and (b) below, On-Line Generation Resources that are assigned Non-Spin Ancillary Service Resource Responsibility during an Operating Hour shall always be deployed in that Operating Hour. This deployment shall be considered as a standing Protocol-directed Non-Spin deployment Dispatch Instruction. Within the 30-second window prior to the top-of-hour clock interval described in paragraph (2) of Section 6.3.2, Activities for Real-Time Operations, the QSE shall respond to the standing Non-Spin deployment Dispatch Instruction for those Generation Resources assigned Non-Spin Ancillary Service Resource Responsibility effective at the top-of-hour by adjusting the Non-Spin Ancillary Service Schedule telemetry. The QSE shall set the Non-Spin Ancillary Service Schedule telemetry equal to the portion of Non-Spin being provided from power augmentation if the portion being

provided from power augmentation is participating as Off-Line Non-Spin, otherwise it shall be set to 0. As described in Section 6.5.7.2, Resource Limit Calculator, ERCOT shall adjust the HASL and LASL based on the QSE's telemetered Non-Spin Ancillary Service Schedule to account for such deployment and to make the energy from the full amount of the Non-Spin Ancillary Service Resource Responsibility available to SCED. A Non-Spin deployment Dispatch Instruction from ERCOT is not required and these Generation Resources must be able to Dispatch their Non-Spin Ancillary Service Resource Responsibility in response to a SCED Base Point deployment instruction. The provisions of this paragraph (5) do not apply to:

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

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

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

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

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

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

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

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

(a) The Resource name;

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

(c) The anticipated duration of deployment.

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

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

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

[NPRR863, NPRR1000, NPRR1010, and NPRR1131: Replace applicable portions of Section 6.5.7.6.2.3 above with the following upon system implementation for NPRR863, NPRR1000, or NPRR1131; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

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

procedure to recover deployed RRS, ECRS, or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that awarded on an individual Resource.

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

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

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

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

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

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

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

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

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

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

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

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

(a) The Resource name;

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

(c) The anticipated duration of deployment.

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

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

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

[NPRR863 and NPRR1010: Insert applicable portions of Section 6.5.7.6.2.4 below upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.6.2.4 Deployment and Recall of ERCOT Contingency Reserve Service

(1) ECRS is intended to:

(a) Help restore the frequency to 60 Hz within ten minutes of a significant frequency deviation;

(b) Provide energy to avoid or during the implementation of an EEA; and

(c) Provide backup to Reg-Up.

(2) ERCOT shall deploy ECRS to meet NERC Standards and other performance criteria as specified in these Protocols and the Operating Guides, by one or more of the following:

(a) ERCOT shall issue ECRS deployment Dispatch Instructions, specifying the required MW output, over ICCP for Resources awarded ECRS with a Resource Status of ONSC.

(b) Dispatch Instruction for deployment of Load Resources energy via electronic Messaging System.

(3) Energy from Resources providing ECRS may also be manually deployed by ERCOT pursuant to Section 6.5.9, Emergency Operations.

(4) ERCOT shall use SCED and Non-Spin as soon as practicable to recover ECRS reserves.

(5) Following a manual ECRS deployment to Load Resources, excluding Controllable Load Resources, or Resources telemetering a Resource Status of ONSC, the QSE's obligation to deliver ECRS remains in effect until ERCOT issues a recall instruction.

(6) For Generation Resources and Controllable Load Resources providing ECRS, Base Points include ECRS energy as well as any other energy dispatched by SCED. A Resource must be able to be fully dispatched by SCED to its ECRS Ancillary Service award within the ten-minute time frame according to its telemetered ramp rate that reflects the Resource's capability of providing ECRS.

(7) Each Resource providing ECRS shall meet the deployment performance requirements specified in Section 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria.

(8) ERCOT shall issue deployment instructions for Load Resources providing ECRS via XML. Such instructions shall contain the MW requested.

(9) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire Ancillary Service award or, if only partial deployment is possible, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(10) ERCOT shall recall deployed ECRS capacity provided from Resource telemetering Resource Status of ONSC once system frequency recovers above 59.98 Hz.

(11) ERCOT shall recall ECRS deployment provided from Load Resource that is not a Controllable Load Resource once PRC is above a pre-defined threshold, as described in the Operating Guides.

6.5.7.7 Voltage Support Service

(1) ERCOT shall coordinate with TSPs the creation and maintenance of Voltage Profiles as described in Section 3.15, Voltage Support.

(2) ERCOT shall instruct the interconnecting TSP, or the TSP's agent, to make Voltage Set Point adjustments, as necessary, within the Generation Resource's Unit Reactive Limit (URL) provided to ERCOT. The interconnecting TSP, or the TSP's agent, shall instruct any QSE or Resource Entity representing a Generation Resource to make the Voltage Set Point adjustments instructed by ERCOT, or as the TSP determines to be necessary. If ERCOT determines that a Generation Resource should be instructed to provide additional MVAr beyond its URL or that a Generation Resource's real power output should be decreased to allow the Generation Resource to provide additional Reactive Power beyond the URL, ERCOT shall issue a Resource-specific Dispatch Instruction requiring any change in Reactive Power and/or real power output, except that ERCOT may not require a Generation Resource to exceed its excitation limits.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall instruct the interconnecting TSP, or the TSP's agent, to make Voltage Set Point adjustments, as necessary, within the Generation Resource's or ESR's Corrected Unit Reactive Limit (CURL) provided to ERCOT. The interconnecting TSP, or the TSP's agent, shall instruct any QSE or Resource Entity representing a Generation Resource or ESR to make the Voltage Set Point adjustments instructed by ERCOT, or as the TSP determines to be necessary. If ERCOT determines that a Generation Resource or ESR should be instructed to provide additional MVAr beyond its URL or that a Generation Resource's or ESR's real power output should be decreased to allow the Generation Resource or ESR to provide additional Reactive Power beyond the URL, ERCOT shall issue a Resource-specific Dispatch Instruction requiring any change in Reactive Power and/or real power output, except that ERCOT may not require a Generation Resource or ESR to exceed its operational limits.

(3) ERCOT and TSPs shall develop procedures for the operation of transmission-controlled reactive Resources in order to minimize the dependence on generation-supplied reactive Resources. For Generation Resources required to provide Voltage Support Service (VSS), GSU transformer tap settings must be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

[NPRR989: Replace paragraph (3) above with the following upon system implementation:]

(3) ERCOT and TSPs shall develop procedures for the operation of transmission-controlled reactive equipment in order to minimize the dependence on Reactive Power supplied by Generation Resources and ESRs. For Generation Resources and ESRs required to provide Voltage Support Service (VSS), GSU transformer tap settings must

be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

(4) Each TSP, under ERCOT's direction, is responsible for monitoring and ensuring that all Generation Resources required to provide VSS have their dynamic reactive capability deployed in approximate proportion to their respective capability requirements.

[NPRR989: Replace paragraph (4) above with the following upon system implementation:]

(4) Each TSP, under ERCOT's direction, is responsible for monitoring and ensuring that all Generation Resources and ESRs required to provide VSS have their dynamic reactive capability deployed in approximate proportion to their respective capability requirements.

(5) Each Generation Resource required to provide VSS shall follow its Voltage Set Point as directed by ERCOT, the interconnecting TSP, or the TSP's agent, within the operating Reactive Power capability of the Generation Resource.

[NPRR989: Replace paragraph (5) above with the following upon system implementation:]

(5) Each Generation Resource and ESR required to provide VSS shall follow its Voltage Set Point as directed by ERCOT, the interconnecting TSP, or the TSP's agent, within the operating Reactive Power capability of the Generation Resource or ESR.

(6) Each interconnecting TSP, or the TSP's agent, shall telemeter via ICCP the Real-Time Voltage Set Point to ERCOT at the Point of Interconnection Bus (POIB) for each Generation Resource interconnected to the TSP's system required to provide VSS. Each interconnecting TSP, or the TSP's agent shall modify the telemetered Voltage Set Point to match any verbal Voltage Set Point instructions as soon as practicable. ERCOT shall telemeter the Real-Time desired Voltage Set Point and the TSP-designated POIB kV measurement via ICCP to each QSE representing a Generation Resource. Each QSE representing a Generation Resource shall provide in Real-Time the desired Voltage Set Point and the associated POIB kV measurement provided by ERCOT to the Resource Entity for that Generation Resource.

[NPRR989: Replace paragraph (6) above with the following upon system implementation:]

(6) Each interconnecting TSP, or the TSP's agent, shall telemeter via ICCP the Real-Time Voltage Set Point to ERCOT at the Point of Interconnection Bus (POIB) for each Generation Resource and ESRs interconnected to the TSP's system required to provide VSS. Each interconnecting TSP, or the TSP's agent shall modify the telemetered

Voltage Set Point to match any verbal Voltage Set Point instructions as soon as practicable. ERCOT shall telemeter the Real-Time desired Voltage Set Point and the TSP-designated POIB kV measurement via ICCP to each QSE representing a Generation Resource or an ESR. Each QSE representing a Generation Resource or an ESR shall provide in Real-Time the desired Voltage Set Point and the associated POIB kV measurement provided by ERCOT to the Resource Entity for that Generation Resource or ESR.

6.5.7.8 Dispatch Procedures

(1) ERCOT shall issue all Resource Dispatch Instructions to the QSE that represents the affected Resource. ERCOT and QSEs are responsible for complying with Dispatch Instructions as prescribed in the Nodal Operating Guides. A QSE may provide a Resource Status of ONTEST for a Generation Resource not providing Ancillary Services to indicate that the Resource is currently undergoing unit testing and is blocked from SCED Dispatch. A QSE may provide a Resource Status of STARTUP for a Generation Resource not providing Ancillary Services to indicate that the Resource is currently undergoing a start-up sequence which requires manual control below or above its telemetered LSL to stabilize the Resource prior to its availability for SCED Dispatch. Generation Resources with a Resource Status of ONTEST will be provided a Base Point equal to the net real power telemetry at the time of the SCED execution. ERCOT may not issue Dispatch Instructions to the QSE for Generation Resources with a Resource Status of ONTEST except:

(a) For Dispatch Instructions that are a part of testing; or

(b) During conditions when the Resource is the only alternative for solving a transmission constraint; or

(c) During Force Majeure Events that threaten the reliability of the ERCOT System.

(2) Each QSE shall immediately forward any valid Dispatch Instruction to the appropriate Resource or group of Resources or identify a reason for non-compliance with the Dispatch Instruction to ERCOT in accordance with Section 6.5.7.9, Compliance with Dispatch Instructions.

(3) If ERCOT believes that a Resource has inadequately responded to a Dispatch Instruction, ERCOT shall notify the QSE representing the Resource as soon as practicable.

(4) ERCOT shall record all voice conversations that occur in the communication of Verbal Dispatch Instructions (VDIs).

(5) By mutual agreement of the TSP and ERCOT, Dispatch Instructions to the TSP may be provided to the TSP's TO. In that case, issuance of the Dispatch Instruction to the TO is considered issuance to the TSP, and the TSP must comply with the Dispatch Instruction

exactly as if it had been issued directly to the TSP, whether or not the TO accurately conveys the Dispatch Instruction to the TSP.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) By mutual agreement of the TSP, DCTO, and ERCOT, Dispatch Instructions to the TSP or DCTO may be provided to the TSP's or DCTO's Transmission Operator (TO). In that case, issuance of the Dispatch Instruction to the TO is considered issuance to the TSP or DCTO, and the TSP or DCTO must comply with the Dispatch Instruction exactly as if it had been issued directly to the TSP or DCTO, whether or not the TO accurately conveys the Dispatch Instruction to the TSP or DCTO.

(6) ERCOT shall direct VDIs to the Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources as deemed necessary by ERCOT to effectuate actions for the total Generation Resource for instances in which electronic instructions are not feasible.

6.5.7.9 Compliance with Dispatch Instructions

(1) Except as otherwise specified in this Section, each TSP and each QSE shall comply fully and promptly with a Dispatch Instruction issued to it, unless in the sole and reasonable judgment of the TSP or QSE, such compliance would create an undue threat to safety, undue risk of bodily harm or undue damage to equipment, or the Dispatch Instruction is otherwise not in compliance with these Protocols.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Except as otherwise specified in this Section, each TSP, DCTO, and QSE shall comply fully and promptly with a Dispatch Instruction issued to it, unless in the sole and reasonable judgment of the TSP, DCTO, or QSE, such compliance would create an

undue threat to safety, undue risk of bodily harm or undue damage to equipment, or the Dispatch Instruction is otherwise not in compliance with these Protocols.

(2) If the recipient of a Dispatch Instruction does not comply because in the sole and reasonable judgment of the TSP or QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment, then the TSP or QSE must immediately notify ERCOT and provide the reason for non-compliance.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) If the recipient of a Dispatch Instruction does not comply because in the sole and reasonable judgment of the TSP, DCTO, or QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment, then the TSP, DCTO, or QSE must immediately notify ERCOT and provide the reason for non-compliance.

(3) If the recipient of a Dispatch Instruction recognizes that the Dispatch Instruction conflicts with other valid instructions or is invalid, the recipient shall immediately notify ERCOT of the conflict and request resolution. ERCOT shall resolve the conflict by issuing another Dispatch Instruction.

(4) ERCOT's final Dispatch Instruction to a QSE in effect applies for all Protocol-related processes. If the QSE does not comply after receiving the final Dispatch Instruction, the QSE remains liable for failure to meet its obligations under the Protocols and remains liable for any charges resulting from such failure.

(5) ERCOT's final Dispatch Instruction to a TSP in effect applies for all Protocol-related processes. If the TSP does not comply after receiving the final Dispatch Instruction, the TSP remains liable for such failure under these Protocols under the TSP's Agreement with ERCOT.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) ERCOT's final Dispatch Instruction to a TSP or DCTO in effect applies for all Protocol-related processes. If the TSP or DCTO does not comply after receiving the final Dispatch Instruction, the TSP or DCTO remains liable for such failure under these Protocols under the TSP's or DCTO's Agreement with ERCOT.

(6) In all cases in which compliance with a Dispatch Instruction is disputed, both ERCOT and the QSE or TSP shall document their communications, agreements, disagreements, and reasons for their actions, to enable resolution of the dispute through the Alternative Dispute Resolution (ADR) process in Section 20, Alternative Dispute Resolution Procedure.

[NPRR857: Replace paragraph (6) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(6) In all cases in which compliance with a Dispatch Instruction is disputed, both ERCOT and the QSE, TSP, or DCTO shall document their communications, agreements, disagreements, and reasons for their actions, to enable resolution of the dispute through the Alternative Dispute Resolution (ADR) process in Section 20, Alternative Dispute Resolution Procedure.

(7) An Intermittent Renewable Resource (IRR) must comply with Dispatch Instructions when receiving a flag signifying that the IRR has received a Base Point below the HDL used by SCED.

[NPRR1111: Replace paragraph (7) above with the following upon system implementation of SCR819:]

(7) An Intermittent Renewable Resource (IRR) must comply with Dispatch Instructions when receiving a flag signifying that the IRR has received a Base Point below the HDL used by SCED or the IRR has been instructed not to exceed its Base Point.

6.5.7.10 IRR Ramp Rate Limitations

(1) Each IRR that is part of a Standard Generation Interconnection Agreement (SGIA) signed on or after January 1, 2009 shall limit its ramp rate to 20% per minute of its nameplate rating (MWs) as registered with ERCOT when responding to or released from an ERCOT deployment.

(2) The requirement of paragraph (1) above does not apply during a Force Majeure Event or during intervals in which a decremental deployment instruction coincides with a demonstrated decrease in the available IRR.

(3) Each IRR that is part of an SGIA signed on or before December 31, 2008 and that controls power output by means other than turbine stoppage shall limit its ramp rate to 20% per minute of its nameplate rating (MWs) as registered with ERCOT when responding to or released from an ERCOT deployment.

(4) The requirement of paragraph (3) above does not apply during a Force Majeure Event, during intervals in which a decremental deployment instruction coincides with a demonstrated decrease in the available IRR, or during unit start up and shut down mode.

(5) The ramp rate requirement of paragraph (3) above shall not apply to an IRR during a limited compliance transition period if the IRR:

(a) Meets the technical specifications of paragraph (3) above but does not comply with the ramp rate requirement; and

(b) Submitted a compliance plan to ERCOT on or before June 1, 2009 that details the technical limitations leading to non-compliance, a work plan to achieve compliance by a reasonable date, and a ramp rate mitigation plan describing the IRR’s best efforts to adhere to the IRR ramp rate limitation during the applicable compliance transition period.

(6) The ramp rate requirement of paragraph (3) above shall not apply to an IRR that:

(a) Does not meet the technical specifications of paragraph (3) above; and

(b) Submitted an operations plan to ERCOT on or before June 1, 2009 describing the IRR’s best efforts to adhere to the IRR ramp rate limitation.

(7) IRRs subject to the ramp rate limitations of paragraphs (1) and (3) above are exempt from the requirements of the applicable paragraph upon receipt of a valid Dispatch Instruction from ERCOT to exceed the applicable ramp rate limitation when necessary to protect ERCOT System reliability.

(8) IRRs that operate under a RAS are exempt from the ramp rate limitations of paragraphs (1) and (3) above when decreasing unit output to avoid RAS activation.

(9) IRRs that meet the requirements of paragraphs (1) and (3) above are compliant with the ramp rate limitation requirements when the number of eligible one-minute intervals with an average ramp rate of 25% or less of nameplate capacity is equal to or greater than 90% of the eligible one-minute intervals in any one of three consecutive months. Intervals where paragraphs (2), (4), (7) or (8) above apply shall be excluded as eligible intervals for this performance metric. ERCOT shall initiate a review process with the IRR where the IRR's score is less than 90%.

[NPRR1029: Insert Section 6.5.7.11 below upon system implementation:]

6.5.7.11 DC-Coupled Resource Ramp Rate Limitations

(1) A DC-Coupled Resource that does not meet any of the conditions in paragraph (1) of Section 3.8.7, DC-Coupled Resources, shall adhere to the ramp rate restrictions established in Section 6.5.7.10, IRR Ramp Rate Limitations.

6.5.8 Verbal Dispatch Instruction Confirmation

(1) Following the issuance of a VDI by ERCOT to a QSE for a Generation Resource, ERCOT will provide the QSE with an electronic confirmation of the VDI for Settlement purposes.

(2) A VDI confirmation shall contain the following information:

(a) Operating Day and time ERCOT issued the VDI;

(b) Identification of the QSE for the Resource(s) subject to the VDI, and instructing authority (including the names of the ERCOT Operator and individual that received the VDI);

(c) Identification of the specific Resource(s) subject to the VDI;

(d) Specific actions required of the Resource(s);

(e) Beginning operating level or state of the Resource(s);

(f) Instructed operating level or state of the Resource(s);

(g) Time at which the Resource(s) was required to initiate actions;

(h) Time by which the Resource(s) was required to complete actions; and

(i) Other information relevant to that Dispatch Instruction.

(3) Following receipt by the QSE of the VDI confirmation issued by ERCOT, the QSE shall provide ERCOT with electronic acknowledgement of the VDI confirmation.

6.5.9 Emergency Operations

(1) ERCOT, based on ERCOT System reliability needs, may issue a Dispatch Instruction requiring a Resource to move to a specific output level ("Emergency Base Point").

(2) A QF may only be ordered Off-Line in the case of an ERCOT-declared Emergency Condition with imminent threat to the reliability of the ERCOT System. ERCOT may only Dispatch a QF below its LSL when ERCOT has declared an Emergency Condition and the QF is the only Resource that can provide the necessary relief.

(3) ERCOT shall honor all Resource operating parameters in Dispatch Instructions under normal conditions and Emergency Conditions. During Emergency Conditions, ERCOT may verbally request QSEs to operate its Resources outside normal operating parameters. If such request is received by a QSE, the QSE shall discuss the request with ERCOT in good faith and may choose to comply with the request.

(4) A QSE may not self-arrange for Ancillary Services procured in response to Emergency Conditions.

6.5.9.1 Emergency and Short Supply Operation

(1) ERCOT is responsible for maintaining reliability in normal and Emergency Conditions. The Operating Guides are intended to ensure that minimum standards for reliability are maintained. Minimum standards for reliability are defined by the Operating Guides and the NERC Reliability Standards and include, but are not limited to:

(a) Minimum operating reserve levels;

(b) Criteria for determining acceptable operation of the frequency control system;

(c) Criteria for determining and maintaining system voltages within acceptable limits;

(d) Criteria for maximum acceptable transmission equipment loading levels; and

(e) Criteria for determining when ERCOT is subject to unacceptable risk of widespread cascading Outages.

(2) ERCOT shall, to the fullest extent practicable, utilize the Day-Ahead process, the Adjustment Period process, and the Real-Time process before ordering Resources to specific output levels with Emergency Base Point instructions. It is anticipated that, with effective and timely communication, the market-based tools available to ERCOT will avert most threats to the reliability of the ERCOT System. However, these Protocols do not preclude ERCOT from taking any action to preserve the integrity of the ERCOT System.

6.5.9.2 Failure of the SCED Process

(1) When the SCED process is not able to reach a solution, ERCOT shall issue a Watch.

(2) For intervals that the SCED process fails to reach a solution, then the LMPs, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders for the interval for which no solution was reached are equal to the LMPs, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders in the most recently solved interval. For Settlement Intervals that the Real-Time Settlement Point Prices are identified as erroneous and ERCOT sets the SCED intervals as failed in accordance with Section 6.3, Adjustment Period and Real-Time Operations Timeline, then the LMPs, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders for the failed SCED intervals are equal to the LMPs, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders in the most recently solved SCED interval that is not set as failed. ERCOT shall notify the market of the failure by posting on the ERCOT website. For intervals covering the first 15 minutes of SCED process execution following a failure, ERCOT shall set the LMPs, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders equal to the LMPs, Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders in the most recently solved SCED interval prior to the SCED process failure. ERCOT shall notify the market of this price correction by posting on the ERCOT website.

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

(2) For intervals that the SCED process fails to reach a solution, then the LMPs, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service for the interval for which no solution was reached are equal to the LMPs, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service in the most recently solved interval. For Settlement Intervals that the Real-Time Settlement Point Prices are identified as erroneous, and ERCOT sets the SCED intervals as failed in accordance with Section 6.3, Adjustment Period and Real-Time Operations Timeline, then the LMPs, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, for the failed SCED intervals are equal to the LMPs, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, in the most recently solved SCED interval that is not set as failed. ERCOT shall notify the market of the failure by posting on the ERCOT website. For intervals covering the first 15 minutes of SCED process execution following a failure, ERCOT shall set the LMPs, Real-Time MCPCs, Real-Time

Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, equal to the LMPs, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, in the most recently solved SCED interval prior to the SCED process failure. ERCOT shall notify the market of this price correction by posting on the ERCOT website.

(3) In the event that a Market Suspension is declared in accordance with Section 25, Market Suspension and Restart, upon the effective date and time of the Market Suspension, the Market Suspension Settlement methodology set forth in Section 25.5, Market Suspension and Market Restart Settlement, will supersede the provisions set forth in paragraph (2) above.

(4) Once ERCOT issues a Watch for a SCED process failure, ERCOT may use any of the following measures:

(a) ERCOT may direct the SCED process to relax the active transmission constraints and/or the HASLs and LASLs for specific Resources and resume calculation of LMPs, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders by reducing the Ancillary Service Schedules for the affected Resource, if sufficient supply exists to manage total system needs;

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

(a) ERCOT may direct the SCED process to relax the active transmission constraints;

(b) ERCOT may issue Emergency Base Points for Resources;

(c) ERCOT may manually issue Emergency Base Points for a Resource and must communicate the Resource name, MW output requested, and start time and duration of the Dispatch Instruction to the QSE representing the Resource;

(d) ERCOT may issue an instruction to hold the previous interval; and

(e) A QF, a hydro Generation Resource, or a nuclear-powered Resource may be instructed by ERCOT to operate below its LSL only after all other Resource options have been exhausted.

(5) The Watch continues until the SCED process can reach a solution without using the measures in paragraph (4) above.

6.5.9.3 Communication Prior to and During Emergency Conditions

(1) Effective, accurate, and timely communication between ERCOT, TSPs, and QSEs is essential. Each QSE must be provided adequate information to make informed decisions and must receive the information with sufficient advance notice to facilitate Resource and Load responses.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Effective, accurate, and timely communication between ERCOT, TSPs, DCTOs, and QSEs is essential. Each QSE must be provided adequate information to make informed decisions and must receive the information with sufficient advance notice to facilitate Resource and Load responses.

(2) The type of communication ERCOT issues is determined primarily on the basis of the time available for the market to respond before an Emergency Condition occurs. The timing of these communications could range from days in advance to immediate. If there is insufficient time to allow the market to react, ERCOT may bypass one or more of the communication steps.

(3) ERCOT shall consider the severity of the potential Emergency Condition as it determines which of the communications to use as set forth in the following subsections. The severity of the Emergency Condition could be limited to an isolated local area, or the condition might cover large areas affecting several entities, or the condition might be an ERCOT-wide condition potentially affecting the entire ERCOT System.

(4) The following Sections describe the types of communications that will be issued by ERCOT to inform all QSEs and TSPs of the operating situation. These communications may relate to transmission, distribution, or Generation or Load Resources. The communications must specify the severity of the situation, the area affected, the areas potentially affected, and the anticipated duration of the Emergency Condition.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) The following Sections describe the types of communications that will be issued by ERCOT to inform all QSEs, TSPs, and DCTOs of the operating situation. These communications may relate to transmission, distribution, or Generation or Load Resources. The communications must specify the severity of the situation, the area affected, the areas potentially affected, and the anticipated duration of the Emergency Condition.

6.5.9.3.1 Operating Condition Notice

(1) ERCOT will issue an Operating Condition Notice (OCN) to inform Market Participants of a possible future need for more Resources due to conditions that could affect ERCOT System reliability. OCNs are for informational purposes only, and ERCOT exercises no additional operational authority with the issuance of this type of notice, but may solicit additional information from QSEs in order to determine whether the issuance of an Advisory, Watch, or Emergency Notice is warranted. The OCN is the first of three levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

(2) When time permits, ERCOT will issue an OCN before issuing an Advisory, Watch, or Emergency Notice. However, issuance of an OCN may not require action on the part of any Market Participant, but rather serves as a notice to Market Participants that some attention to the changing conditions may be warranted. OCNs serve to communicate to QSEs the need to take extra precautions to be prepared to serve the Load during times when contingencies are most likely to arise.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) When time permits, ERCOT will issue an OCN before issuing an Advisory, Watch, or Emergency Notice. However, issuance of an OCN may not require action on the part of any Market Participant, but rather serves as notice to Market Participants that some attention to the changing conditions may be warranted. OCNs serve to communicate to QSEs the need to take extra precautions to be prepared to serve the Load during times when contingencies are most likely to arise.

(3) Reasons for OCNs include, but are not limited to, unplanned transmission Outages, insufficient Resources to meet forecasted conditions, and weather-related concerns such as anticipated freezing temperatures, hurricanes, wet weather, and ice storms.

(4) ERCOT will monitor actual and forecasted weather for the ERCOT Region and adjacent NERC regions. When adverse weather conditions are expected, ERCOT may confer with TSPs and QSEs regarding the potential for adverse reliability impacts and contingency preparedness. Based on its assessment of the potential for adverse conditions, ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no more than seven days from the date of the request. The specific information that may be requested shall be defined in the Operating Guides. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) ERCOT will monitor actual and forecasted weather for the ERCOT Region and adjacent NERC regions. When adverse weather conditions are expected, ERCOT may confer with TSPs, DCTOs, and QSEs regarding the potential for adverse reliability impacts and contingency preparedness. Based on its assessment of the potential for adverse conditions, ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no more than seven days from the date of the request. The specific information that may be requested shall be defined in the Operating Guides. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

(5) QSEs and TSPs are expected to establish and maintain internal procedures for monitoring actual and forecasted weather and for implementing appropriate measures when the potential for adverse weather or other conditions (which could threaten ERCOT System reliability) arise.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) QSEs, TSPs, and DCTOs are expected to establish and maintain internal procedures for monitoring actual and forecasted weather and for implementing appropriate measures when the potential for adverse weather or other conditions (which could threaten ERCOT System reliability) arise.

6.5.9.3.1.1 Advance Action Notice

(1) ERCOT may issue an AAN in anticipation of a possible Emergency Condition. Any AAN will identify actions ERCOT expects to take to address the possible Emergency Condition unless the need for ERCOT action is alleviated by QSE and/or TSP actions taken, or by other system developments that occur, before a time stated in the AAN.

(2) An AAN may not require action on the part of any Market Participant but may include additional information so that Market Participants can modify their plans in such a way that mitigates the need for ERCOT to take additional actions.

(3) An AAN will be canceled if ERCOT determines that the possible Emergency Condition has been alleviated by QSE or TSP action, by ERCOT action, or by other system developments.

6.5.9.3.2 Advisory

(1) An Advisory is the second of three levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

(2) ERCOT shall issue an Advisory for reasons such as, but not limited to, the following:

  (a) When it recognizes that conditions are developing or have changed and more Ancillary Services will be needed to maintain current or near-term operating reliability;

  (b) When weather or ERCOT System conditions require more lead-time than the normal DAM allows;

  (c) When communications or other controls are significantly limited; or

  (d) When ERCOT Transmission Grid conditions are such that operations within security criteria as defined in the Operating Guides are not likely or possible because of Forced Outages or other conditions unless a Constraint Management Plan (CMP) exists.

(3) The Advisory must communicate existing constraints. ERCOT shall notify TSPs and QSEs of the Advisory, and QSEs shall notify appropriate Resources and Load Serving

Entities (LSEs). ERCOT shall communicate with TSPs as needed to confirm their understanding of the condition and to determine the availability of Transmission Facilities. For the purposes of verifying submitted information, ERCOT may communicate with QSEs.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) The Advisory must communicate existing constraints. ERCOT shall notify TSPs, DCTOs, and QSEs of the Advisory, and QSEs shall notify appropriate Resources and Load Serving Entities (LSEs). ERCOT shall communicate with TSPs and DCTOs as needed to confirm their understanding of the condition and to determine the availability of Transmission Facilities. For the purposes of verifying submitted information, ERCOT may communicate with QSEs.

(4) Although an Advisory is for information purposes, ERCOT may exercise its authority, in such circumstances, to increase Ancillary Service requirements above the quantities originally specified in the Day-Ahead in accordance with procedures. ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no more than seven days from the date of the request. The specific information that may be requested shall be defined in the Operating Guide. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

(5) When an Advisory is issued for PRC below 3,000 MW and ERCOT expects system conditions to deteriorate to the extent that an EEA Level 2 or 3 may be experienced, ERCOT shall evaluate constraints active in SCED and determine which constraints have the potential to limit generation output.

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that

Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs and DCTOs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

(i) A 15-Minute Rating is available to allow for additional transmission capacity for use in congestion management, if an EEA Level 2 or 3 is declared, and post-contingency actions can be taken within 15 minutes to return the flow to within the Emergency Rating. Such actions may include, but are not limited to, reducing the generation that increased output as a result of enforcing the 15-Minute Rating rather than the Emergency Rating;

(ii) Post-contingency loading of the Transmission Facilities is expected to be at or below Normal Rating within two hours; or

(iii) Additional transmission capacity could allow for additional output from a limited Generation Resource by taking one of the following actions:

(A) Restoring Transmission Elements that are out of service;

(B) Reconfiguring the transmission system; or

(C) Making adjustments to phase angle regulator tap positions.

If ERCOT determines that one of the above-mentioned actions allows for additional output from a limited Generation Resource, ERCOT may instruct the TSPs to take the action(s) during the Advisory to allow for additional output from the limited Generation Resource.

(b) ERCOT shall also coordinate with TSPs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double circuit, weather conditions that indicate a high risk of insulator flashover on the double circuit, repeated Forced Outages of the individual circuits that are part of the double circuit in the preceding 48 hours, or fire in progress in the right of way of the double circuit.

(c) The actions detailed in this Section shall be supplemental to the development and maintenance of CMPs as otherwise directed by the Protocols or Operating Guides.

6.5.9.3.3 Watch

(1) A Watch is the third of three levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

(2) ERCOT shall issue a Watch when ERCOT determines that:

(a) Conditions have developed such that additional Ancillary Services are needed in the current Operating Period;

(b) There are insufficient Ancillary Services or Energy Offers in the DAM;

[NPRR1010: Delete paragraphs (a) and (b) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(c) Market-based congestion management techniques embedded in SCED as specified in these Protocols will not be adequate to resolve transmission security violations;

(d) Forced Outages or other abnormal operating conditions have occurred, or may occur that require operations with active violations of security criteria as defined in the Operating Guides unless a CMP exists;

(e) ERCOT varies from timing requirements or omits one or more Day-Ahead or Adjustment Period and Real-Time procedures;

(f) ERCOT varies from timing requirements or omits one or more scheduling procedures in the Real-Time process; or

(g) The SCED process fails to reach a solution, whether or not ERCOT is using one of the measures specified in paragraph (4) of Section 6.5.9.2, Failure of the SCED Process.

(3) With the issuance of a Watch pursuant to paragraph (2)(a) above, ERCOT may exercise its authority to immediately procure the following services from existing offers:

(a) Regulation Services;

(b) RRS services; and

[NPRR863: Insert item (c) below upon system implementation and renumber accordingly:]

(c) ECRS services; and

(c) Non-Spin services.

(4) If ERCOT issues a Watch because insufficient Ancillary Service Offers were received in the DAM or Supplemental Ancillary Service Market (SASM), and if the Watch does not result in sufficient offers and the DAM or SASM is executed with insufficient offers, then ERCOT may acquire the insufficient amount of Ancillary Services as follows:

(a) The SASM process shall be conducted in accordance with Section 6.4.9.2.2, SASM Clearing Process. If the SASM process is not sufficient, then;

(b) The HRUC process shall be conducted to commit planned Off-Line Resources qualified to provide the Ancillary Service(s) that are insufficient in accordance with Section 5.2.2.2, RUC Process Timeline After an Aborted Day-Ahead Market. If the HRUC process is not sufficient, then;

(c) If the insufficiency arose due to insufficient Ancillary Service Offers received in the DAM or ERCOT needs to increase the Ancillary Service requirements after DAM clearing, ERCOT may assign the insufficient amounts of Ancillary Service(s) to QSEs with planned On-Line Resources qualified to provide the insufficient Ancillary Service(s), even if there are no existing Ancillary Service Offers for those QSEs' Resources. ERCOT shall prorate the required Ancillary Service capacity among QSEs representing On-Line capacity not already reserved for Ancillary Services in the COP in a way that maximizes the distribution of the assignment.

(d) A QSE may request cancellation of the assignment of Ancillary Services to its On-Line Resources if there are equipment or Resource control issues which limit the ability of the Resources to provide the Ancillary Services. If ERCOT accepts the cancellation, ERCOT may require QSEs to submit supporting information describing the Resource control issues.

[NPRR1010: Delete paragraphs (3) and (4) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(5) ERCOT shall post the Watch message electronically to the ERCOT website and shall provide verbal notice via the TO Hotline and the QSE Hotline. Corrective actions identified by ERCOT must be communicated through Dispatch Instructions to all TSPs, DSPs and QSEs required to implement the corrective action. Each QSE shall immediately notify the Market Participants that it represents of the Watch. To minimize the effects on the ERCOT System, each TSP or DSP shall identify and prepare to implement actions, including restoration of transmission lines as appropriate and preparing for Load shedding. ERCOT may instruct TSPs or DSPs to reconfigure ERCOT System elements as necessary to improve the reliability of the ERCOT System. On notice of a Watch, each QSE, TSP, and DSP shall prepare for an Emergency Condition in case conditions worsen. ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no more than seven days from the date of the

request. The specific information that may be requested shall be defined in the Operating Guides. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) ERCOT shall post the Watch message electronically to the ERCOT website and shall provide verbal notice via the TO Hotline and the QSE Hotline. Corrective actions identified by ERCOT must be communicated through Dispatch Instructions to all TSPs, DCTOs, DSPs and QSEs required to implement the corrective action. Each QSE shall immediately notify the Market Participants that it represents of the Watch. To minimize the effects on the ERCOT System, each TSP or DSP shall identify and prepare to implement actions, including restoration of transmission lines as appropriate and preparing for Load shedding. ERCOT may instruct DCTOs, TSPs or DSPs to reconfigure ERCOT System elements as necessary to improve the reliability of the ERCOT System. On notice of a Watch, each QSE, DCTO, TSP, and DSP shall prepare for an Emergency Condition in case conditions worsen. ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no more than seven days from the date of the request. The specific information that may be requested shall be defined in the Operating Guides. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

6.5.9.3.4 Emergency Notice

(1) Emergency Notice is the communication issued by ERCOT when operating in an Emergency Condition.

(2) ERCOT shall issue an Emergency Notice for one or both of the following reasons:

(a) ERCOT cannot maintain minimum reliability standards (for reasons including fuel shortages) during the Operating Period using every Resource practicably obtainable from the market; or

(b) Immediate action cannot be taken to avoid or relieve a Transmission Element operating above its Emergency Rating.

(3) The actions ERCOT takes during an Emergency Condition depend on the nature and severity of the situation.

(4) ERCOT is considered to be in an Emergency Condition whenever ERCOT Transmission Grid status is such that a violation of security criteria, as defined in the Operating Guides, presents the threat of uncontrolled separation or cascading Outages and/or large-scale service disruption to Load (other than Load being served from a radial transmission line) and/or overload of a Transmission Element, and no timely solution is obtainable through SCED or CMPs.

(5) If the Emergency Condition is the result of a transmission problem, ERCOT shall act immediately to return the ERCOT System to a reliable condition, including instructing any QSE representing a Resource to change the Resource's output, curtailing any remaining DC Tie Load, and instructing TSPs or DSPs to drop Load. In addition, ERCOT may instruct any QSE representing an ESR to suspend ESR charging if ERCOT determines that a Load reduction by the ESR is capable of mitigating the transmission problem. An ESR co-located behind a Point of Interconnection (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.

(6) In the event that Load is curtailed or Load Resource(s) or ERS Resource(s) are deployed due to a transmission problem as described in paragraph (5) above, ERCOT shall post within one day an operations message to the ERCOT website listing the event's date, start and end time, MW quantity of Load curtailment or deployment instruction, and the substation(s) or geographic area in which the event occurred.

(7) If the Emergency Condition is the result of an Ancillary Service insufficiency, then ERCOT shall follow the EEA procedures.

[NPRR1010: Delete paragraph (7) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.5.9.4 Energy Emergency Alert

(1) At times it may be necessary to reduce ERCOT System Demand because of a temporary decrease in available electricity supply. To provide orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT shall initiate and coordinate the implementation of the EEA following the steps set forth below in Section 6.5.9.4.2, EEA Levels.

(2) The goal of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT System to reduce the chance of cascading Outages.

(3) ERCOT's operating procedures must meet the following goals:

(a) Use of market processes to the fullest extent practicable without jeopardizing the reliability of the ERCOT System;

(b) Use of RRS, other Ancillary Services, and ERS to the extent permitted by ERCOT System conditions;

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

(b) Use of RRS, ECRS, other Ancillary Services, and ERS to the extent permitted by ERCOT System conditions;

(c) Maximum use of ERCOT System capability;

(d) Maintenance of station service for nuclear-powered Generation Resources;

(e) Securing startup power for Generation Resources;

(f) Operation of Generation Resources during loss of communication with ERCOT;

(g) Restoration of service to Loads in the manner defined in the Operating Guides; and

(h) Management of Interconnection Reliability Operating Limits (IROLs) shall not change.

(4) ERCOT is responsible for coordinating with QSEs, TSPs, and DSPs to monitor ERCOT System conditions, initiating the EEA levels, notifying Market Participants, and coordinating the implementation of the EEA levels while maintaining transmission security limits.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) ERCOT is responsible for coordinating with QSEs, DCTOs, TSPs, and DSPs to monitor ERCOT System conditions, initiating the EEA levels, notifying Market Participants, and coordinating the implementation of the EEA levels while maintaining transmission security limits.

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

(6) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using the DC Ties or by using BLTs to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with NERC scheduling guidelines.

(7) Some of the EEA steps are not applicable if transmission security violations exist. There may be insufficient time to implement all EEA levels in sequence, however, to the extent practicable, ERCOT shall use Ancillary Services that QSEs have made available in the market to maintain or restore reliability.

[NPRR1010: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Some of the EEA steps are not applicable if transmission security violations exist. There may be insufficient time to implement all EEA levels in sequence, however, to the extent practicable, ERCOT shall use Ancillary Service capabilities of Resources in the market to maintain or restore reliability.

(8) ERCOT may immediately implement EEA Level 3 any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes and shall immediately implement EEA Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

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

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (5)(a) of Section 6.5.9.3.2, Advisory, ERCOT may control the post-contingency flow to within the 15-Minute Rating in SCED. After PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(11) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (5)(b) of Section 6.5.9.3.2, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all other double-circuit contingencies identified in paragraph (5)(b) of Section 6.5.9.3.2, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency

after PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

6.5.9.4.1 General Procedures Prior to EEA Operations

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

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

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

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

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

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

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

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

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

(2) When PRC falls below 3,000 MW and is not projected to be recovered above 3,000 MW within 30 minutes following the deployment of Non-Spin, ERCOT may deploy available contracted ERS-10 and ERS-30 via an XML message followed by a VDI to the QSE Hotline. The ERS-10 and ERS-30 ramp periods shall begin at the completion of the VDI.

(a) ERS-10 and ERS-30 may be deployed at any time in a Settlement Interval. ERS-10 and ERS-30 may be deployed either simultaneously or separately, and in any order, at the discretion of ERCOT operators.

(b) Upon deployment, QSEs shall instruct their ERS Resources in ERS-10 and ERS-30 to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, until either ERCOT releases the ERS-10 and ERS-30 deployment or the ERS-10 and ERS-30 Resources have reached their maximum deployment time.

(c) ERCOT shall notify QSEs of the release of ERS-10 and ERS-30 via an XML message followed by VDI to the QSE Hotline. The VDI shall represent the official notice of ERS-10 and ERS-30 release.

(d) Upon release, an ERS Resource shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the release.

6.5.9.4.2 EEA Levels

(1) ERCOT will declare an EEA Level 1 when PRC falls below 2,300 MW and is not projected to be recovered above 2,300 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 1:

(a) ERCOT shall take the following steps to maintain steady state system frequency near 60 Hz and maintain PRC above 1,750 MW:

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

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

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

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

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

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

(b) QSEs shall:

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

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

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

(ii) Suspend any ongoing ERCOT required Resource performance testing; and

(iii) 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 (iii) above with the following upon system implementation:]

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

(A) The ESR has a current SCED Base Point Instruction, 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 1,750 MW and is not projected to be recovered above 1,750 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

(a) In addition to the measures associated with EEA Level 1, ERCOT shall take the following steps to maintain steady state system frequency at a minimum of 59.91 Hz and maintain PRC above 1,430 MW:

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

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

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

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

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

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

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

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

(A) Instruct QSEs to deploy 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 based on their group designation from the Day-Ahead. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from any of the groups not designated for deployment if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a QSE Hotline VDI, which shall initiate the ten-minute deployment period;

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

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

(C) The ERCOT Operator may deploy all groups of Load Resources providing RRS at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a QSE Hotline VDI, which shall initiate the ten-minute deployment period; and

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

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

(D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource obligation which may be deployed to interrupt under paragraph (A) 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. ERCOT will declare an EEA Level 3 when PRC cannot be maintained above 1,430 MW or when the clock-minute average system frequency falls below 59.91 Hz for 25 consecutive minutes. Upon declaration of an EEA Level 3, ERCOT will implement any measures associated with EEA Levels 1 and 2 that have not already been implemented.

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

(b) When PRC falls below 1,000 MW and is not projected to be recovered above 1,000 MW within 30 minutes, or when the clock-minute average frequency falls below 59.91 Hz for 25 consecutive minutes, ERCOT shall direct all TOs to shed firm Load, in 100 MW blocks, distributed as documented in the Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover 1,000 MW of PRC within 30 minutes.

(c) TOs and TDSPs may shed Load connected to under-frequency relays pursuant to an ERCOT Load shed directive issued during EEA Level 3 so long as each affected TO continues to comply with its Under-Frequency Load Shed (UFLS) obligation as described in Nodal Operating Guide Section 2.6.1, Automatic Firm Load Shedding, and its Load shed obligation as described in Nodal Operating Guide Section 4.5.3.4, Load Shed Obligation.

6.5.9.4.3 Restoration of Market Operations

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

6.5.9.5 Block Load Transfers between ERCOT and Non-ERCOT Control Areas

(1) BLTs are procedures that transfer Loads normally located in the ERCOT Control Area to a non-ERCOT Control Area. Similarly, when a non-ERCOT Control Area experiences certain transmission contingencies or short-supply conditions, ERCOT may agree to the implementation of BLT procedures that transfer Loads normally located in a non-ERCOT Control Area to the ERCOT Control Area. BLTs are restricted to the following conditions:

(a) All modeled BLTs shall be implemented only with approval from ERCOT, unless a governmental order is issued requiring the use of the BLT.

(i) BLTs shall be registered with ERCOT. Such registration shall be subject to ERCOT approval.

(ii) For all BLTs, the TSP in the ERCOT Control Area responsible for implementing the BLT shall coordinate with ERCOT in the implementation and execution of BLTs to ensure the reliability of the ERCOT System is not jeopardized and to ensure sufficient generation capacity is available prior to serving additional Load.

(b) BLTs that are comprised of looped systems may be tied to the non-ERCOT Control Area's electrical system(s) through multiple interconnection points at the same time. Transfers of looped configurations are permitted only if all interconnection points are registered and netted under a single Electric Service Identifier (ESI ID) and represented by a singled TSP or DSP or netted behind the Non-Opt-In Entity (NOIE) metering points.

(c) BLTs of Load to the ERCOT Control Area are:

 (i) Treated as non-competitive wholesale Load in the Load Zone containing the ERCOT breaker or switch that initiated the BLT;

 (ii) Registered in accordance with Section 6.5.9.5.1, Registration and Posting of BLT Points, by the TSP in the ERCOT Control Area responsible for implementing the BLT;

 (iii) Responsible for Unaccounted For Energy (UFE) allocations and Transmission Losses consistent with similarly situated NOIE metering points; and

 (iv) Permitted only if the BLT will not jeopardize the reliability of the ERCOT System. Under an Emergency Notice, BLTs that have been implemented may be curtailed or terminated by ERCOT to maintain the reliability of the ERCOT System.

(d) BLTs of Load from the ERCOT Control Area are:

 (i) Treated as generation and Load in the ERCOT Settlement system unless the Load is in a NOIE territory and the NOIE has opted for the Load transfer to be treated as a NOIE Load reduction by not submitting a Settlement Block Load Transfer Registration Form. BLTs may only be instructed with the permission of the affected non-ERCOT Control Area. Under an emergency condition in a non-ERCOT Control Area, BLTs that have been implemented may be curtailed or terminated by the non-ERCOT Control Area to maintain the reliability of the non-ERCOT system;

 (ii) Registered in accordance with Section 6.5.9.5.1 by the TSP in the ERCOT Control Area responsible for implementing the BLT; and

 (iii) Permitted only if the BLT will not jeopardize the reliability of the ERCOT System.

(e) BLTs specifically exclude transfers of Load between ERCOT and non-ERCOT Control Areas that occur behind a retail Settlement Meter.

(f) BLTs may be used in the restoration of service to Customers if the transfers will not jeopardize the reliability of the ERCOT System.

(g) For any BLT established in a TDSP area that is open to Customer Choice, the TDSP must register the BLT metering point for Settlement. For any BLT established in a NOIE territory, the NOIE may either register the BLT for Settlement or may forgo registration and have the Load transfer settled as a Load increase or reduction. As a condition for Settlement, a BLT must be registered using the Settlement Block Load Transfer Registration Form found on the

ERCOT website, and each BLT metering point must use revenue quality, 15-minute Interval Data Recorder (IDR) Meters. ERCOT may impose additional metering requirements it considers necessary to ensure ERCOT System reliability and integrity.

(h) SCADA telemetry on switching devices at BLT points that are deemed necessary by ERCOT to be modeled in the Network Operations Model must be provided by the TSP registering the BLT.

6.5.9.5.1 Registration and Posting of BLT Points

(1) The necessary Market Participant registration, agreements, metering, and ERCOT Settlement systems, as applicable, must be in place before implementation of any BLT. At its sole discretion, ERCOT may exclude a BLT of ten MW or less from the Network Operations Model and associated telemetry requirements.

(2) ERCOT may require any size of BLT that has been deployed in accordance with Section 6.5.9.5.2, Scheduling and Operation of BLTs, to be in the Network Operations Model with required telemetry if ERCOT determines it is warranted due to the length of time deployed.

(3) BLTs that transfer Load from the ERCOT Control Area to a non-ERCOT Control Area are treated as generation and Load by ERCOT and assigned a Resource ID and, if in a NOIE territory, an ESI ID unless the Load is in a NOIE territory and the NOIE has not registered the BLT for Settlement pursuant to paragraph (1)(g) of Section 6.5.9.5, Block Load Transfers between ERCOT and Non-ERCOT Control Areas. The ERCOT Control Area TSP or DSP associated with the BLT Point has the responsibility for registering the BLT and the creation and maintenance of BLT Resource IDs for Settlement purposes. For any BLT that a NOIE has registered for Settlement, the NOIE shall designate NOIE metering point(s), a Resource Entity, and a QSE for Settlement purposes. For BLTs occurring on TSP or DSP systems open to Customer Choice, the non-ERCOT Control Area Entity receiving the transferred Load shall designate a registered Resource Entity and acknowledge a QSE for Settlement purposes in accordance with Section 16.5, Registration of a Resource Entity. The ERCOT Control Area TSP or DSP must complete the applicable BLT registration form. This BLT registration form along with the metering design and data documentation is the basis for establishing the ERCOT data model of the BLT and associated metering points for Settlement as applicable.

(4) BLTs that transfer Load from a non-ERCOT Control Area to the ERCOT Control Area are treated as a non-competitive wholesale Load by ERCOT and assigned an ESI ID unless the BLT is in a NOIE territory and the NOIE has not registered the BLT for Settlement. The ERCOT Control Area TSP or DSP associated with the BLT Point has the responsibility for registering the BLT and the creation and maintenance of BLT ESI IDs. Customers connected to the ERCOT System do not require an ESI ID separate from the assigned BLT ESI ID. The TSP or DSP that registers the BLT Point shall provide the ESI ID associated with the BLT to ERCOT. For BLTs occurring on NOIE TSP or DSP

systems, the NOIE may designate NOIE metering point(s), an LSE, and a QSE for Settlement purposes. Load associated with NOIE BLTs that do not have an LSE or QSE for Settlement purposes will be reflected in the NOIE's 4-Coincident Peak (4-CP) calculation. For BLTs occurring on TSP or DSP systems open to Customer Choice, the non-ERCOT Control Area Entity shall designate a registered ERCOT LSE and acknowledge a QSE for Settlement purposes in accordance with Section 16.3, Registration of Load Serving Entities.

(5) A "BLT Point" is the metering point for a BLT Resource ID or for a BLT ESI ID.

(6) ERCOT shall post the registration details of all registered BLTs to the MIS Secure Area.

6.5.9.5.2 Scheduling and Operation of BLTs

(1) For BLTs that are deployed in an emergency and are not modeled in the Network Operations Model, the responsible TSP shall notify ERCOT as soon as practicable after deployment.

(2) For BLTs that transfer Load to a non-ERCOT Control Area, ERCOT shall confirm the BLT's availability with the non-ERCOT Control Area before implementation.

(3) Any energy associated with the non-ERCOT Control Area Load BLT Point is treated as a Load obligation of the QSE representing the LSE with the BLT ESI ID as registered for Settlement purposes in accordance with Section 6.5.9.5.1, Registration and Posting of BLT Points.

6.5.9.6 Black Start

(1) Black Start Service (BSS) is obtained by ERCOT through Black Start Agreements with QSEs for Generation Resources capable of self-starting or Generation Resources within close proximity of a non-ERCOT Control Area that are capable of starting from that non-ERCOT Control Area under a firm standby power supply contract, without support from the ERCOT System, or transmission equipment in the ERCOT System. Generation Resources that can be started with a minimum of pre-coordinated switching operations using ERCOT transmission equipment within the ERCOT System may be considered for BSS only where switching may be accomplished within one hour or less.

(2) ERCOT may Dispatch BSS pursuant to an emergency restoration plan to begin restoration of the ERCOT System to a secure operating state after a Blackout. General restoration actions for all Market Participants are described in the Operating Guides.

6.6 Settlement Calculations for the Real-Time Energy Operations

6.6.1 Real-Time Settlement Point Prices

(1) Real-Time energy Settlements use Real-Time Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs. For each Security-Constrained Economic Dispatch (SCED) Locational Marginal Price (LMP) calculated at each Settlement Point in the SCED process, an administrative price floor of -$251/MWh will be applied to Real-Time Settlement Point Prices after adding the sum of the Real-Time On-Line Reliability Deployment Price Adders and the Real-Time On-Line Reserve Price Adder. ERCOT shall assign an LMP to de-energized Electrical Buses for use in the calculation of the Real-Time Settlement Point Prices by using heuristic rules applied in the following order:

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

(1) Real-Time energy Settlements use Real-Time Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs. For each Security-Constrained Economic Dispatch (SCED) Locational Marginal Price (LMP) calculated at each Settlement Point in the SCED process, an administrative price floor of -$251/MWh will be applied to Real-Time Settlement Point Prices after adding the Real-Time Reliability Deployment Price Adders for Energy. ERCOT shall assign an LMP to de-energized Electrical Buses for use in the calculation of the Real-Time Settlement Point Prices by using heuristic rules applied in the following order:

(a) Use an appropriate LMP predetermined by ERCOT as applicable to a specific Electrical Bus; or if not so specified

(b) Use the following rules in order:

(i) Use average LMP for Electrical Buses within the same station having the same voltage level as the de-energized Electrical Bus, if any exist.

(ii) Use average LMP for all Electrical Buses within the same station, if any exist.

(iii) Use System Lambda.

6.6.1.1 Real-Time Settlement Point Price for a Resource Node

(1) The Real-Time Settlement Point Price for a Resource Node Settlement Point is the time-weighted average of the sum of the Real-Time LMPs, Real-Time On-Line Reliability Deployment Price Adders, and the Real-Time On-Line Reserve Price Adders. The Real-Time Settlement Point Price for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP} = \mathbf{Max\ (-\$251,\ (\sum_{y} (RNWF_{\mathit{y}} * (RTLMP_{\mathit{y}} + RTORPA_{\mathit{y}} + RTORDPA_{\mathit{y}}))))}$$

Where the Resource Node weighting factor is:

$$\mathbf{RNWF}_{y} = \mathbf{TLMP}_{y} / \sum_{y} \mathbf{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point for the 15-minute Settlement Interval.
RTORPA $_{y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTLMP $_{y}$	\$/MWh	*Real-Time Locational Marginal Price per interval*—The Real-Time LMP at the Settlement Point for the SCED interval *y*.
RTORDPA $_{y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

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

(1) The Real-Time Settlement Point Price for a Resource Node Settlement Point is the time-weighted average of the sum of the Real-Time LMPs and the Real-Time Reliability Deployment Price Adder for Energy. The Real-Time Settlement Point Price for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP} = \mathbf{Max\ (-\$251, (} \sum_{y} \mathbf{(RNWF}_{y} \mathbf{* (RTLMP}_{y} \mathbf{+ RTRDPA}_{y}\mathbf{))))}$$

Where the Resource Node weighting factor is:

$$\mathbf{RNWF}_{y} = \mathbf{TLMP}_{y} / \sum_{y} \mathbf{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point for the 15-minute Settlement Interval.
RTLMP $_{y}$	\$/MWh	*Real-Time Locational Marginal Price per interval*—The Real-Time LMP at the Settlement Point for the SCED interval *y*.

RTRDPA $_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

(2) The Real-Time Settlement Point Price at the logical Resource Node for a Combined Cycle Train shall be determined in accordance with paragraph (1) above using a Real-Time LMP calculated for the logical Resource Node in each SCED Interval as follows:

(a) The Real-Time LMP for the logical Resource Node of a Combined Cycle Train for each SCED interval is calculated as follows:

For a Combined Cycle Train that is On-Line in the SCED interval:

$$\textbf{RTLMP}_{y} = \sum_{CCGR\_PhyR} \textbf{RTLMP}_{CCGR\_PhyR,\,y} * \textbf{RTONCCGRWF}_{CCGR\_PhyR}$$

For a Combined Cycle Train that is Off-Line in the SCED interval:

$$\textbf{RTLMP}_{y} = \sum_{CCT\_PhyR} \textbf{RTLMP}_{CCT\_PhyR,\,y} * \textbf{RTOFFCCGRWF}_{CCT\_PhyR}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTLMP $_{y}$	\$/MWh	*Real-Time Locational Marginal Price at a logical Resource Node for a Combined Cycle Train*—The Real-Time LMP at the Combined Cycle Generation Resource logical Resource Node for a SCED interval *y*.
RTLMP $_{CCGR\_PhyR,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at a generation unit Resource Node designated in a Combined Cycle Train registration for the On-Line Combined Cycle Generation Resource*—The Real-Time LMP at the Resource Node of a generation unit designated in a Combined Cycle Train registration for the On-Line Combined Cycle Generation Resource for the SCED interval *y*.
RTLMP $_{CCT\_PhyR,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at a generation unit Resource Node registered to the Combined Cycle Train*—The Real-Time LMP at the Resource Node of a generation unit designated in a Combined Cycle Train registration for the SCED interval *y*.
RTONCCGRWF $_{CCGR\_PhyR,\,y}$	none	*Real-Time On-Line Combined Cycle Generation Resource Weighting Factor*—The Real Time Combined Cycle Generation Resource weighting factor for a generation unit designated in a Combined Cycle Train registration for the On-Line Combined Cycle Generation Resource for the SCED interval *y*.
RTOFFCCGRWF $_{CCT\_PhyR,\,y}$	none	*Real-Time Off-Line Combined Cycle Generation Resource Weighting Factor*—The Real-Time Combined Cycle Generation Resource weighting factor for a generation unit designated in a Combined Cycle

		Train registration when the whole Combined Cycle Train is Off-Line for the SCED interval *y*.
CCGR_PhyR	none	A generation unit designated in a Combine Cycle Train registration for the On-Line Combined Cycle Generation Resource.
CCT_PhyR	none	A generation unit designated in a Combine Cycle Train registration
c	none	A binding transmission constraint for the SCED interval *y*.
y	none	A SCED interval in the 15-minute Settlement Interval.

(b) For an On-Line Combined Cycle Train, the weight factor for each generation unit registered in an On-Line Combined Cycle Generation Resource shall be the Real-Time power output telemetry in each SCED interval for each generation unit registered in the Combined Cycle Generation Resource divided by the total Real-Time power output telemetry for all of the generation units registered in the Combined Cycle Generation Resource. For an Off-Line Combined Cycle Train, the weight factor for each generation unit designated in a Combined Cycle Train registration shall be its High Reasonability Limit (HRL) divided by the total sum of the HRL for all generation units registered in the Combined Cycle Train.

Where:

$$\mathbf{RTONCCGRWF}_{CCGR\_PhyR,\, y} = \mathbf{TG}_{CCGR\_PhyR} \,/\, \sum_{CCGR\_PhyR} \mathbf{TG}_{CCGR\_PhyR}$$

$$\mathbf{RTOFFCCGRWF}_{CCT\_PhyR,\, y} = \mathbf{HRL}_{CCT\_PhyR} \,/\, \sum_{CCT\_PhyR} \mathbf{HRL}_{CCT\_PhyR}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{RTONCCGRWF}_{CCGR\_PhyR,\, y}$	none	*Real-Time On-Line Combined Cycle Generation Resource Weighting Factor*—The Real Time Combined Cycle Generation Resource weighting factor for a generation unit designated in a Combined Cycle Train registration for the On-Line Combined Cycle Generation Resource for the SCED interval *y*.
$\text{TG}_{CCGR\_PhyR,\, y}$	MW	*Telemetered Generation for a Combined Cycle Generation Resource generation unit*—The telemetered Real-Time power generation for a generation unit designated in a Combined Cycle Train registration for the On-Line Combined Cycle Generation Resource at the time of State Estimator execution for the SCED interval *y*.
$\text{RTOFFCCGRWF}_{CCT\_PhyR,\, y}$	none	*Real-Time Off-Line Combined Cycle Generation Resource Weighting Factor*—The Real Time Combined Cycle Generation Resource weighting factor for a generation unit designated in a Combined Cycle Train registration when the whole Combined Cycle Train is Off-Line for the SCED interval *y*.
HRL_{CCT_PhyR}	MW	*High Reasonability Limit*—The HRL as specified in the ERCOT-approved Resource Registration data for a generation unit designated in a Combined Cycle Train registration.
CCGR_PhyR	none	A generation unit designated in a Combine Cycle Train registration for the On-Line Combined Cycle Generation Resource.
CCT_PhyR	none	A generation unit designated in a Combine Cycle Train registration.
y	none	A SCED interval in the 15-minute Settlement Interval.

6.6.1.2 Real-Time Settlement Point Price for a Load Zone

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

$$\mathbf{RTSPP} \quad = \quad \mathbf{Max\ (-\$251,\ ((\sum_{y} TLMP_{\mathit{y}} * LZLMP_{\mathit{y}})\ /\ \sum_{y} TLMP_{\mathit{y}}) +} \\ \mathbf{RTRSVPOR + RTRDP)}$$

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

$$\text{LZLMP}_{y} \quad = \quad \sum_{b} (\text{RTLMP}_{b,\,y} * \text{SEL}_{b,\,y})\ /\ \sum_{b} \text{SEL}_{b,\,y}$$

For a DC Tie Load Zone:

$$\text{LZLMP}_{y} \quad = \quad \text{RTLMP}_{b,\,y}$$

Where:

$$\text{RTRSVPOR} = \quad \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \quad \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \quad \text{TLMP}_{y}\ /\ \sum_{y} \text{TLMP}_{y}$$

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

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

$$\mathbf{RTSPP} \quad = \quad \mathbf{Max\ (-\$251,\ ((\sum_{y} TLMP_{\mathit{y}} * LZLMP_{\mathit{y}})\ /\ \sum_{y} TLMP_{\mathit{y}}) +} \\ \mathbf{RTRDP)}$$

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

$$\text{LZLMP}_{y} = \sum_{b} (\text{RTLMP}_{b,\,y} * \text{SEL}_{b,\,y}) / \sum_{b} \text{SEL}_{b,\,y}$$

For a DC Tie Load Zone:

$$\text{LZLMP}_{y} = \text{RTLMP}_{b,\,y}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

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

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

For all Load Zones except DC Tie Load Zones:

$$\text{LZWF}_{b,\,y} = (\text{SEL}_{b,\,y} * \text{TLMP}_{y}) / [\sum_{y} \sum_{b} (\text{SEL}_{b,\,y} * \text{TLMP}_{y})]$$

For a DC Tie Load Zone:

$$\text{LZWF}_{b,\,y} = (\text{SEL}_{b,\,y} * \text{TLMP}_{y}) / [\sum_{y} \sum_{b} (\text{SEL}_{b,\,y} * \text{TLMP}_{y})]$$

$$\text{SEL}_{b,\,y} = 1$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point, for the 15-minute Settlement Interval.
RTSPPEW	$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point p, for the 15-minute Settlement Interval that is weighted by the state-estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Interval.
$\text{RTLMP}_{b,\,y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus b in the Load Zone, for the SCED interval y.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time Price Adder for On-Line Reserves for the SCED interval y.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval y.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval y within the Settlement Interval.
$\text{LZWF}_{b,\,y}$	none	*Load Zone Weighting Factor per bus per interval*—The weight used in the Load Zone Settlement Point Price calculation for Electrical Bus b, for the portion of the SCED interval y within the 15-minute Settlement Interval.
LZLMP_{y}	$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED interval y.
$\text{SEL}_{b,\,y}$	MW	*State Estimator Load at bus per interval*—The Load value from State Estimator, including a calculated net Load value at each Private Use Network and adjustments to account for Distribution Generation Resource (DGR) and Distribution Energy Storage Resource (DESR) injections and withdrawals that are settled at a Resource Node, excluding Wholesale Storage Load (WSL) and Non-WSL Energy Storage Resource (ESR) Charging Load for Electrical Bus b in the Load Zone, for the SCED interval y.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval y within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

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

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

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

$$\mathbf{RTSPPEW} \quad = \quad \mathbf{Max\ [-\$251,\ (\sum_{y} \sum_{b} (RTLMP_{\,b,\,y} * LZWF_{\,b,\,y}) + RTRDP)]}$$

For all Load Zones except DC Tie Load Zones:

$$\text{LZWF}_{\,b,\,y} \quad = \quad (\text{SEL}_{\,b,\,y} * \text{TLMP}_{\,y}) \,/\, [\sum_{y} \sum_{b} (\text{SEL}_{\,b,\,y} * \text{TLMP}_{\,y})]$$

For a DC Tie Load Zone:

$$\text{LZWF}_{\,b,\,y} \quad = \quad (\text{SEL}_{\,b,\,y} * \text{TLMP}_{\,y}) \,/\, [\sum_{y} \sum_{b} (\text{SEL}_{\,b,\,y} * \text{TLMP}_{\,y})]$$

$$\text{SEL}_{\,b,\,y} \quad = \quad 1$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTRDPA}_{\,y})$$

$$\text{RNWF}_{\,y} \quad = \quad \text{TLMP}_{\,y} \,/\, \sum_{y} \text{TLMP}_{\,y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point, for the 15-minute Settlement Interval.
RTSPPEW	\$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point p, for the 15-minute Settlement Interval that is weighted by the state-estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Interval.
$\text{RTLMP}_{\,b,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus b in the Load Zone, for the SCED interval y.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$\text{RTRDPA}_{\,y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval y.
$\text{RNWF}_{\,y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval y within the Settlement Interval.

$LZWF_{b,y}$	none	*Load Zone Weighting Factor per bus per interval*—The weight used in the Load Zone Settlement Point Price calculation for Electrical Bus *b*, for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$LZLMP_{y}$	$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED interval *y*.
$SEL_{b,y}$	MW	*State Estimator Load at bus per interval*—The Load value from State Estimator, including a calculated net Load value at each Private Use Network and adjustments to account for Distribution Generation Resource (DGR) and Distribution Energy Storage Resource (DESR) injections and withdrawals that are settled at a Resource Node, excluding Wholesale Storage Load (WSL) and Non-WSL Energy Storage Resource (ESR) Charging Load, for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

6.6.1.3 Real-Time Settlement Point Price for a Hub

(1) The Real-Time Settlement Point Price at a Hub is determined according to the methodology included in the definition of that Hub in Section 3.5.2, Hub Definitions.

6.6.1.4 Load Zone LMPs

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

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

For all Load Zones except DC Tie Load Zones:

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

For a DC Tie Load Zone:

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

The above variables are defined as follows:

Variable	Unit	Description
$LZLMP_{y}$	$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED interval *y*.

RTLMP $_{b,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per SCED interval*—The Real-Time LMP at Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
LZWF $_{b,\,y}$	None	*Load Zone State Estimator Load Weighting Factor per bus per SCED interval*—The weight used in the Load Zone LMP calculation for Electrical Bus *b* for the SCED interval *y*.
SEL $_{b,\,y}$	MW	*State Estimator Load at bus per SCED interval*—The Load from the State Estimator, including a calculated net Load value at each Private Use Network and adjustments to account for DGR and DESR injections and withdrawals that are settled at a Resource Node, excluding WSL and Non-WSL ESR Charging Load for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
y	None	A SCED interval.
b	None	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

6.6.1.5 Hub LMPs

(1) The Hub LMPs shall be posted on the ERCOT website.

(2) For each defined Hub except for the ERCOT Hub Average 345 kV Hub, the Hub LMP is the arithmetic average of the Real-Time LMPs of the Hub Buses included in the Hub. The Hub LMP for a SCED Interval is calculated as follows:

$$\mathbf{HUBLMP}_{Hub,\,y} = \sum_{hb} (\mathbf{HUBDF}_{hb,\,Hub} * \mathbf{RTHBP}_{hb,\,Hub,\,y}),\ \mathbf{if\ HB}_{Hub} \neq \mathbf{0}$$

$$\mathbf{HUBLMP}_{Hub,\,y} = \mathbf{HUBLMP}_{ERCOT345Bus},\ \mathbf{if\ HB}_{Hub} = \mathbf{0}$$

Where:

$$\text{RTHBP}_{hb,\,Hub,\,y} = \sum_{b} (\text{HBDF}_{b,\,hb,\,Hub} * \text{RTLMP}_{b,\,hb,\,Hub,\,y})$$

$$\text{HUBDF}_{hb,\,Hub} = 1 / \text{HB}_{Hub},\ \text{if HB}_{Hub} \neq 0$$

$$\text{HUBDF}_{hb,\,Hub} = 0,\ \text{if HB}_{Hub} = 0$$

$$\text{HBDF}_{b,\,hb,\,Hub} = 1 / \text{B}_{hb,\,Hub},\ \text{if B}_{hb,\,Hub} \neq 0$$

$$\text{HBDF}_{b,\,hb,\,Hub} = 0,\ \text{if B}_{hb,\,Hub} = 0$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
HUBLMP $_{Hub,\,y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RTHBP $_{hb,\,Hub,\,y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.

$\text{RTLMP}_{b,\ hb,\ Hub,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$\text{HUBDF}_{hb,\ Hub}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$\text{HBDF}_{b,\ hb,\ Hub}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
$\text{B}_{hb,\ Hub}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
HB_{Hub}	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.
Hub	none	One of the following Hubs: ERCOT Bus Average 345 kV Hub, North 345 kV Hub, South 345 kV Hub, Houston 345 kV Hub, or the West 345 kV Hub
hb	none	A Hub Bus that is a component of the Hub.
y	none	A SCED interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.

(3) The Hub LMP for the ERCOT Hub Average 345 kV Hub (ERCOT 345) for a SCED Interval is calculated as follows:

$$\mathbf{HUBLMP}_{\boldsymbol{ERCOT345,\ y}} = (\mathbf{HUBLMP}_{\boldsymbol{NORTH345,\ y}} + \mathbf{HUBLMP}_{\boldsymbol{SOUTH345,\ y}} + \mathbf{HUBLMP}_{\boldsymbol{HOUSTON345,\ y}} + \mathbf{HUBLMP}_{\boldsymbol{WEST345,\ y}})\ /\ 4$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$\text{HUBLMP}_{ERCOT345,\ y}$	\$/MWh	*Hub Locational Marginal Price for the ERCOT345*—The Hub LMP for the ERCOT Hub Average 345 kV Hub (ERCOT 345), for the SCED Interval *y*.
$\text{HUBLMP}_{NORTH345,\ y}$	\$/MWh	*Hub Locational Marginal Price for the NORTH345*—The Hub LMP for the North 345 kV Hub (NORTH 345), for the SCED Interval *y*.
$\text{HUBLMP}_{SOUTH345,\ y}$	\$/MWh	*Hub Locational Marginal Price for the SOUTH345*—The Hub LMP for the South 345 kV Hub (SOUTH 345), for the SCED Interval *y*.
$\text{HUBLMP}_{HOUSTON345,\ y}$	\$/MWh	*Hub Locational Marginal Price for the HOUSTON345*—The Hub LMP for the Houston 345 kV Hub (HOUSTON 345), for the SCED Interval *y*.
$\text{HUBLMP}_{WEST345,\ y}$	\$/MWh	*Hub Locational Marginal Price for the WEST345*—The Hub LMP for the West 345 kV Hub (WEST 345), for the SCED Interval *y*.

[NPRR1057: Replace applicable portions of Section 6.6.1.5 above with the following upon system implementation of NPRR941 or NPRR1057:]

6.6.1.5 Hub LMPs

(1) The Hub LMPs shall be posted on the ERCOT website.

(2) For each defined Hub except for the ERCOT Hub Average 345 kV Hub and the ERCOT Bus Average 345 kV Hub, the Hub LMP is the arithmetic average of the Real-Time LMPs of the Hub Buses included in the Hub. The Hub LMP for a SCED Interval is calculated as follows:

$$\mathbf{HUBLMP}_{Hub,\,y} = \sum_{hb} (\mathbf{HUBDF}_{hb,\,Hub} * \mathbf{RTHBP}_{hb,\,Hub,\,y}), \text{ if } \mathbf{HB}_{Hub} \neq 0$$

$$\mathbf{HUBLMP}_{Hub,\,y} = \mathbf{HUBLMP}_{ERCOT345Bus,y}, \text{ if } \mathbf{HB}_{Hub} = 0$$

Where:

$$\text{RTHBP}_{hb,\,Hub,\,y} = \sum_{b} (\text{HBDF}_{b,\,hb,\,Hub} * \text{RTLMP}_{b,\,hb,\,Hub,\,y})$$

$$\text{HUBDF}_{hb,\,Hub} = 1 / \text{HB}_{Hub}, \text{ if HB}_{Hub} \neq 0$$

$$\text{HUBDF}_{hb,\,Hub} = 0, \text{ if HB}_{Hub} = 0$$

$$\text{HBDF}_{b,\,hb,\,Hub} = 1 / \text{B}_{hb,\,Hub}, \text{ if B}_{hb,\,Hub} \neq 0$$

$$\text{HBDF}_{b,\,hb,\,Hub} = 0, \text{ if B}_{hb,\,Hub} = 0$$

The above variables are defined as follows:

Variable	Unit	Description
HUBLMP $_{Hub,\,y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RTHBP $_{hb,\,Hub,\,y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
HUBLMP $_{ERCOT345Bus,y}$	\$/MWh	*Hub Locational Marginal Price for the ERCOT345Bus*—The Hub LMP for the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus), for the SCED Interval *y*.
RTLMP $_{b,\,hb,\,Hub,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
HUBDF $_{hb,\,Hub}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b,\,hb,\,Hub}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
B $_{hb,\,Hub}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.

HB_{Hub}	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.
Hub	none	One of the following Hubs: North 345 kV Hub, South 345 kV Hub, Houston 345 kV Hub, West 345 kV Hub, the Panhandle 345 kV Hub, or the Lower Rio Grande Valley 138/345 kV Hub.
hb	none	A Hub Bus that is a component of the Hub with at least one energized component.
y	none	A SCED interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.

(3) The Hub LMP for the ERCOT Hub Average 345 kV Hub (ERCOT 345) for a SCED Interval is calculated as follows:

$$\mathbf{HUBLMP}_{\boldsymbol{ERCOT345,\,y}} = (\mathbf{HUBLMP}_{\boldsymbol{NORTH345,\,y}} + \mathbf{HUBLMP}_{\boldsymbol{SOUTH345,\,y}} + \mathbf{HUBLMP}_{\boldsymbol{HOUSTON345,\,y}} + \mathbf{HUBLMP}_{\boldsymbol{WEST345,\,y}}) \,/\, \mathbf{4}$$

The above variables are defined as follows:

Variable	Unit	Description
$HUBLMP_{ERCOT345,\,y}$	$/MWh	*Hub Locational Marginal Price for the ERCOT345*—The Hub LMP for the ERCOT Hub Average 345 kV Hub (ERCOT 345), for the SCED Interval *y*.
$HUBLMP_{NORTH345,\,y}$	$/MWh	*Hub Locational Marginal Price for the NORTH345*—The Hub LMP for the North 345 kV Hub (NORTH 345), for the SCED Interval *y*.
$HUBLMP_{SOUTH345,\,y}$	$/MWh	*Hub Locational Marginal Price for the SOUTH345*—The Hub LMP for the South 345 kV Hub (SOUTH 345), for the SCED Interval *y*.
$HUBLMP_{HOUSTON345,\,y}$	$/MWh	*Hub Locational Marginal Price for the HOUSTON345*—The Hub LMP for the Houston 345 kV Hub (HOUSTON 345), for the SCED Interval *y*.
$HUBLMP_{WEST345,\,y}$	$/MWh	*Hub Locational Marginal Price for the WEST345*—The Hub LMP for the West 345 kV Hub (WEST 345), for the SCED Interval *y*.

(4) The Hub LMP for the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) for a SCED Interval is calculated as follows:

$$\mathbf{HUBLMP}_{ERCOT345Bus,\,y} = \sum_{hb} (\mathbf{HUBDF}_{hb,ERCOT345Bus} * \mathbf{RTHBP}_{hb,\,ERCOT345Bus,\,y}),\ \mathbf{if\ HB}_{ERCOT345Bus} \neq \mathbf{0}$$

$$\mathbf{HUBLMP}_{ERCOT345Bus,\,y} = \mathbf{0,\ if\ HB}_{ERCOT345Bus} = \mathbf{0}$$

Where:

$$RTHBP_{hb,\,ERCOT345Bus,\,y} = \sum_{b} (HBDF_{b,\,hb,\,ERCOT345Bus} * RTLMP_{b,\,hb,\,ERCOT345Bus,\,y})$$

$$HUBDF_{hb,\,ERCOT345Busc} = IF(HB_{ERCOT345Bus} = 0,\ 0,\ 1 \,/\, HB_{ERCOT345Bus})$$

$$\text{HBDF}_{b,\ hb,\ ERCOT345Bus} = \text{IF}(\text{B}_{hb,\ ERCOT345Bus} = 0,\ 0,\ 1\ /\ \text{B}_{hb,\ ERCOT345Bus})$$

Variable	**Unit**	**Description**
$\text{HUBLMP}_{ERCOT345Bus,\ y}$	\$/MWh	*Hub Locational Marginal Price for the ERCOT345Bus*—The Hub LMP for the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus), for the SCED Interval *y*.
$\text{RTHBP}_{hb,\ ERCOT345Bus,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* in ERCOT 345 Bus, for the SCED interval *y*.
$\text{RTLMP}_{b,\ hb,\ ERCOT345Bus,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb* in ERCOT 345 Bus, for the SCED interval *y*.
$\text{HUBDF}_{hb,\ ERCOT345Bus}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$\text{HBDF}_{b,\ hb,\ ERCOT345Bus}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
$\text{HB}_{ERCOT345Bus}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus . The Hub “ERCOT 345 Bus” includes any Hub Bus defined in the Hub “North 345”, “South 345”, “Houston 345” and “West 345”.
$\text{B}_{hb,\ ERCOT345Bus}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of “ERCOT 345 Bus”.
hb	none	A Hub Bus that is a component of the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component. The Hub “ERCOT 345 Bus” includes any Hub Bus defined in the Hub “North 345”, “South 345”, “Houston 345” and “West 345”.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.

[NPRR1010: Insert Section 6.6.1.6 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.6.1.6 Real-Time Market Clearing Prices for Ancillary Services

(1) The Real-Time Market Clearing Price for Capacity (MCPC) for Reg-Up is the time-weighted average of the sum of the Real-Time MCPCs for Reg-Up and Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Up of each SCED interval in the 15-minute Settlement Interval. The Real-Time MCPC for Reg-Up for a 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTMCPCRU} = \sum_{y} (\textbf{RNWF}_{y} * (\textbf{RTMCPCRUS}_{y} + \textbf{RTRDPARUS}_{y}))$$

Where:

$$\text{RNWF}_y = \text{TLMP}_y / \sum_y \text{TLMP}_y$$

The above variables are defined as follows:

Variable	Unit	Description
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
RTMCPCRUS_y	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up per SCED interval* - The Real-Time MCPC for Reg-Up for the SCED interval *y*.
RTRDPARUS_y	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Up per SCED interval* - The Real-Time price adder for Reg-Up that captures the impact of reliability deployments on Reg-Up prices for the SCED interval y.
RNWF_y	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP_y	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

(2) The Real-Time MCPC for Reg-Down is the time-weighted average of the sum of the Real-Time MCPCs for Reg-Down and Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Down of each SCED interval in the 15-minute Settlement Interval. The Real-Time MCPC for Reg-Down for a 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTMCPCRD} = \sum_y (\textbf{RNWF}_y * (\textbf{RTMCPCRDS}_y + \textbf{RTRDPARDS}_y))$$

Where:

$$\text{RNWF}_y = \text{TLMP}_y / \sum_y \text{TLMP}_y$$

The above variables are defined as follows:

Variable	Unit	Description
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
RTMCPCRDS_y	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down per SCED interval* - The Real-Time MCPC for Reg-Down for the SCED interval *y*.

RTRDPARDS y	\$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Down per SCED interval* - The Real-Time price adder for Reg-Down that captures the impact of reliability deployments on Reg-Down prices for the SCED interval *y*.
RNWF $_y$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

(3) The Real-Time MCPC for RRS is the time-weighted average of the sum of the Real-Time MCPCs for RRS and Real-Time Reliability Deployment Price Adder for Ancillary Service for RRS of each SCED interval in the 15-minute Settlement Interval. The Real-Time MCPC for RRS for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTMCPCRR} = \sum_{y} (\mathbf{RNWF}_{y} * (\mathbf{RTMCPCRRS}_{y} + \mathbf{RTRDPARRS}_{y}))$$

Where:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTMCPCRR	\$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
RTMCPCRRS $_y$	\$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve per SCED interval* - The Real-Time MCPC for RRS for the SCED interval *y.*
RTRDPARRS y	\$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Responsive Reserve per SCED interval* - The Real-Time price adder for RRS that captures the impact of reliability deployments on RRS prices for the SCED interval y.
RNWF $_y$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

(4) The Real-Time MCPC for ECRS is the time-weighted average of the sum of the Real-Time MCPC for ECRS and Real-Time Reliability Deployment Price Adder for Ancillary Service for ECRS of each SCED interval in the 15-minute Settlement

Interval. The Real-Time MCPC for ECRS for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTMCPCECR} = \sum_{y} (\mathbf{RNWF}_{y} * (\mathbf{RTMCPCECRS}_{y} + \mathbf{RTRDPAECRS}_{y}))$$

Where:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve* - The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
RTMCPCECRS $_{y}$	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve per SCED interval* - The Real-Time MCPC for ECRS for the SCED interval *y.*
RTRDPAECRS *y*	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for ECRS per SCED interval* - The Real-Time price adder for ECRS that captures the impact of reliability deployments on ECRS prices for the SCED interval y.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

(5) The Real-Time MCPC for Non-Spin is the time-weighted average of the sum of the Real-Time MCPC for Non-Spin and Real-Time Reliability Deployment Price Adders for Ancillary Service for Non-Spin of each SCED interval in the 15-minute Settlement Interval. The Real-Time MCPC for Non-Spin for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTMCPCNS} = \sum_{y} (\mathbf{RNWF}_{y} * (\mathbf{RTMCPCNSS}_{y} + \mathbf{RTRDPANSS}_{y}))$$

Where:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTMCPCNS	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.

RTMCPCNSS $_{y}$	\$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin per SCED interval* - The Real-Time MCPC for Non-Spin for the SCED interval *y*.
RTRDPANSS $_{y}$	\$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Non-Spin per SCED interval* - The Real-Time price adder for Non-Spin that captures the impact of reliability deployments on Non-Spin prices for the SCED interval y.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

[NPRR1010: Insert Section 6.6.1.7 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.6.1.7 Real-Time Reliability Deployment Prices for Ancillary Services

(1) The Real-Time Reliability Deployment Price for Ancillary Service for Reg-Up (RTRDPRU) is the time-weighted average of the sum of the Real-Time Reliability Deployment Price Adders for Ancillary Service for Reg-Up per SCED interval. The Real-Time Reliability Deployment Price for Ancillary Service for Reg-Up for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTRDPRU = \sum_{y} (RNWF_{y} * RTRDPARUS_{y})}$$

Where:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDPRU	\$/MW	*Real-Time Reliability Deployment Price for Ancillary Service for Reg-Up* - The Real-Time Reliability Deployment Price for Ancillary Service for Reg-Up for the 15-minute Settlement Interval.
RTRDPARUS $_{y}$	\$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Up per SCED interval* - The Real-Time price adder for Reg-Up that captures the impact of reliability deployments on Reg-Up prices for the SCED interval y.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.

y	none	A SCED interval in the 15-minute Settlement Interval.

(2) The Real-Time Reliability Deployment Price for Ancillary Service for Reg-Down (RTRDPRD) is the time-weighted average of the sum of the Real-Time Reliability Deployment Price Adders for Ancillary Service for Reg-Down per SCED interval. The Real-Time Reliability Deployment Price for Ancillary Service for Reg-Down for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTRDPRD = \sum_{y} (RNWF_{\mathit{y}} * RTRDPARDS_{\mathit{y}})}$$

Where:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDPRD	\$/MW	*Real-Time Reliability Deployment Price for Ancillary Service for Reg-Down* - The Real-Time Reliability Deployment Price for Ancillary Service for Reg-Down for the 15-minute Settlement Interval.
RTRDPARDS *y*	\$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Down per SCED interval* - The Real-Time price adder for Reg-Down that captures the impact of reliability deployments on Reg-Down prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

(3) The Real-Time Reliability Deployment Price for Ancillary Service for Responsive Reserve (RTRDPRRS) is the time-weighted average of the sum of the Real-Time Reliability Deployment Price Adders for Ancillary Service for Responsive Reserve per SCED interval. The Real-Time Reliability Deployment Price for Ancillary Service for Responsive Reserve for a 15-minute Settlement Interval is calculated as follows:

$$\text{RTRDPRRS} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPARRS}_{y})$$

Where:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDPRRS	\$/MW	*Real-Time Reliability Deployment Price for Ancillary Service for Responsive Reserve* - The Real-Time Reliability Deployment Price for Ancillary Service for RRS for the 15-minute Settlement Interval.
RTRDPARRS $_y$	\$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Responsive Reserve per SCED interval* - The Real-Time price adder for RRS that captures the impact of reliability deployments on RRS prices for the SCED interval y.
RNWF $_y$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval y within the Settlement Interval.
TLMP $_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval y within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

(4) The Real-Time Reliability Deployment Price for Ancillary Service for ERCOT Contingency Reserve (RTRDPECR) is the time-weighted average of the sum of the Real-Time Reliability Deployment Price Adders for Ancillary Service for ERCOT Contingency Reserve per SCED interval. The Real-Time Reliability Deployment Price for Ancillary Service for ERCOT Contingency Reserve for a 15-minute Settlement Interval is calculated as follows:

$$\text{RTRDPECR} = \sum_{y} (\text{RNWF}_y * \text{RTRDPAECRS}_y)$$

Where:

$$\text{RNWF}_y = \text{TLMP}_y / \sum_{y} \text{TLMP}_y$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDPECR	\$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve* - The Real-Time Reliability Deployment Price for Ancillary Service for ECRS for the 15-minute Settlement Interval.
RTRDPAECRS $_y$	\$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for ECRS per SCED interval* - The Real-Time price adder for ECRS that captures the impact of reliability deployments on ECRS prices for the SCED interval y.
RNWF $_y$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval y within the Settlement Interval.
TLMP $_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval y within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

(5) The Real-Time Reliability Deployment Price for Ancillary Service for ERCOT Non-Spin (RTRDPNS) is the time-weighted average of the sum of the Real-Time Reliability Deployment Price Adders for Ancillary Service for Non-Spin per SCED interval. The Real-Time Reliability Deployment Price for Ancillary Service for Non-Spin for a 15-minute Settlement Interval is calculated as follows:

$$\text{RTRDPNS} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPANSS}_{y})$$

Where:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDPNS	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time Reliability Deployment Price for Ancillary Service for ECRS for the 15-minute Settlement Interval.
RTRDPANSS $_{y}$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Non-Spin per SCED interval* - The Real-Time price adder for Non-Spin that captures the impact of reliability deployments on Non-Spin prices for the SCED interval y.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval.

6.6.2 Load Ratio Share

6.6.2.1 ERCOT Total Adjusted Metered Load for a 15-Minute Settlement Interval

(1) ERCOT total Adjusted Metered Load (AML) (excluding the DC Tie export associated with the Qualified Scheduling Entities (QSEs) under the "Oklaunion Exemption") for a 15-minute Settlement Interval is calculated as follows:

[NPRR1054: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT total Adjusted Metered Load (AML) for a 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTAMLTOT} = \sum_{q} (\max(0, \sum_{p} \textbf{RTAML}_{q,p}))$$

The above variables are defined as follows:

Variable	Unit	Description
RTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the 15-minute Settlement Interval.
RTAML $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load per Qualified Scheduling Entity (QSE) per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
q	none	A QSE. The summation is over all of the QSEs with metered readings in that interval.
p	none	A Settlement Point. The summation is over all of the Settlement Points.

6.6.2.2 QSE Load Ratio Share for a 15-Minute Settlement Interval

(1) Each QSE's Load Ratio Share (LRS) for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LRS}_{q} \quad = \quad \mathbf{(max(0, \sum_{p} RTAML}_{q,\,p}\mathbf{)) \,/\, RTAMLTOT}$$

The above variables are defined as follows:

Variable	Unit	Description
LRS $_{q}$	none	*Load Ratio Share per QSE*—The LRS as defined in Section 2, Definitions and Acronyms, for QSE *q*, for the 15-minute Settlement Interval.
RTAML $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load per Settlement Point per QSE*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
RTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point. The summation is over all of the Settlement Points.

[NPRR1030: Insert paragraphs (2)-(4) below upon system implementation:]

(2) Each QSE's MLRS, excluding DC Tie exports included in RTAML, for ERCOT's peak Load 15-minute Settlement Interval in the calendar month is calculated as follows:

$$\mathbf{MLRS}_{q} \quad = \quad \mathbf{max(0, \sum_{p} (RTAML}_{q,\,p}\mathbf{ - RTAMLDC}_{q,\,p}\mathbf{)) \,/\, (RTAMLTOT - \sum_{q} \sum_{p} RTAMLDC}_{q,\,p}\mathbf{)}$$

The above variables are defined as follows:

Variable	Unit	Description
MLRS $_{q}$	none	*Monthly Load Ratio Share per QSE*—The ratio share of Loads excluding DC Tie Exports for QSE *q*, for the peak Load 15-minute Settlement Interval.
RTAML $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load per Settlement Point per QSE*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.

RTAMLDC $_{q,p}$	MWh	*Real-Time Adjusted Metered Load for DC Ties per Settlement Point per QSE*—The sum of the DC Tie AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
RTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point. The summation is over all of the Settlement Points.

(3) ERCOT total AML per Congestion Management Zone (CMZ) excluding DC Tie exports included in RTAML for ERCOT's peak Load 15-minute Settlement Interval in the calendar month is calculated as follows:

$$\mathbf{RTAMLLZTOT_z = \sum_{q} (max(0, \sum_{p} (RTAML_{\,q,\,p} - RTAMLDC_{\,q,\,p})))}$$

The above variables are defined as follows:

Variable	Unit	Description
RTAMLLZTOT$_z$	MWh	*Real-Time Adjusted Metered Load - Load Zone Total*—The total AML excluding DC Tie exports in CMZ z, for the peak Load 15-minute Settlement Interval in the calendar month.
RTAML $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
RTAMLDC $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load for DC Ties per Settlement Point per QSE*—The sum of the DC Tie AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point in the 2003 ERCOT CMZ.
z	none	A 2003 ERCOT CMZ.

(4) Each QSE's MLRSZ, excluding DC Tie exports included in RTAML, by CMZ for ERCOT's peak Load 15-minute Settlement Interval in the calendar month is calculated as follows:

$$\mathbf{MLRSZ_{\,q,z} = max(0, \sum_{p} (RTAML_{\,q,\,p} - RTAMLDC_{\,q,\,p})) / RTAMLLZTOT_z}$$

The above variables are defined as follows:

Variable	Unit	Description
MLRSZ $_{q,z}$	none	*Monthly Load Ratio Share Zonal per QSE per zone*—The ratio share of QSE *q* for its Load excluding DC Tie Exports in CMZ *z*, for the peak Load 15-minute Settlement Interval in the month.
RTAML $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load per Settlement Point per QSE*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
RTAMLDC $_{q,p}$	MWh	*Real-Time Adjusted Metered Load for DC Ties per Settlement Point per QSE*—The sum of the DC Tie AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.

$RTAMLLZTOT_z$	MWh	*Real-Time Adjusted Metered Load - Load Zone Total*—The total AML excluding DC Tie exports in CMZ z, for the peak Load 15-minute Settlement Interval in the calendar month.
q	none	A QSE.
p	none	A Settlement Point in the 2003 ERCOT CMZ.
z	none	A 2003 ERCOT CMZ.

6.6.2.3 ERCOT Total Adjusted Metered Load for an Operating Hour

(1) ERCOT total AML (excluding the DC Tie export associated with the QSEs under the Oklaunion Exemption) for an Operating Hour is calculated as follows:

[NPRR1054: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT total AML for an Operating Hour is calculated as follows:

$$\mathbf{HRTAMLTOT} = \sum_{q} (\mathbf{max(0,} \sum_{i=1}^{4} \sum_{p} \mathbf{RTAML}_{q,p}\mathbf{)}\ \mathbf{)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
HRTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the Operating Hour.
$RTAML_{q,p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
q	none	A QSE. The summation is over all of the QSEs with metered readings in that interval.
p	none	A Settlement Point. The summation is over all of the Settlement Points.
i	none	A 15-minute Settlement Interval in the Operating Hour. The summation is over all of the Settlement Intervals of the Operating Hour.

6.6.2.4 QSE Load Ratio Share for an Operating Hour

(1) Each QSE's LRS for an Operating Hour is calculated as follows:

$$\mathbf{HLRS}_q = (\mathbf{max(0,} \sum_{i=1}^{4} \sum_{p} \mathbf{RTAML}_{q,p,i}\mathbf{))\ /\ (HRTAMLTOT)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$HLRS_q$	none	*Hourly Load Ratio Share per QSE*—The LRS as defined in Section 2, Definitions and Acronyms, for QSE *q*, for the hour.

RTAML $_{q,\,p,\,i}$	MWh	*Real-Time Adjusted Metered Load per Settlement Point per QSE by interval*—The sum of the AML at the Electrical Buses that are included in the Settlement Point *p*, represented by QSE *q* for the 15-minute Settlement Interval *i*.
HRTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the Operating Hour.
p	none	A Settlement Point. The summation is over all of the Settlement Points.
i	none	A 15-minute Settlement Interval in the Operating Hour. The summation is over all of the Settlement Intervals of the Operating Hour.

[NPRR1030: Insert Section 6.6.2.5 below upon system implementation:]

6.6.2.5 ERCOT Total Adjusted Metered Load for a Month

(1) ERCOT total AML for a calendar month is calculated as follows:

$$\textbf{MRTAMLTOT} = \sum_{q} (\max(0, \sum_{i} \sum_{p} \textbf{RTAML}_{q,\,p,i}))$$

The above variables are defined as follows:

Variable	Unit	Description
MRTAMLTOT	MWh	*Monthly Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the calendar month.
RTAML $_{q,\,p,i}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval *i*.
q	none	A QSE.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.

[NPRR1030 and NPRR1054: Insert applicable portions of Section 6.6.2.6 below upon system implementation:]

6.6.2.6 QSE DC Tie Export Load Ratio Share for a Month

(1) Each QSE's DC Tie Export DCMLRS for a calendar month is calculated as follows:

$$\textbf{DCMLRS}_{q} = \max(0, \sum_{i} \sum_{p} \textbf{RTAMLDC}_{q,\,p,\,i}) / \textbf{MRTAMLTOT}$$

The above variables are defined as follows:

Variable	Unit	Description
DCMLRS $_{q}$	none	*DC Tie Export Monthly Load Ratio Share per QSE*—The ratio share calculated for QSE *q* with DC Tie Exports for the calendar month.

$\text{RTAMLDC}_{q,\,p,\,i}$	MWh	*Real-Time Adjusted Metered Load for DC Ties per Settlement Point per QSE*—The sum of the DC Tie AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval *i*.
MRTAMLTOT	MWh	*Monthly Real-Time Adjusted Metered Load Total*—The total AML in ERCOT, for the calendar month.
q	none	A QSE.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.

[NPRR1030: Insert Section 6.6.2.7 below upon system implementation:]

6.6.2.7 ERCOT Adjusted Metered Load by Congestion Management Zone for a Month

(1) ERCOT total AML per CMZ for a calendar month is calculated as follows:

$$\textbf{MRTAMLLZTOT}_{z} = \sum_{q} (\max(0, \sum_{i} \sum_{p} \textbf{RTAML}_{q,\,p,i}))$$

The above variables are defined as follows:

Variable	Unit	Description
MRTAMLLZTOT_{z}	MWh	*Monthly Real-Time Adjusted Metered Load - Load Zone Total*—The total AML in CMZ z, for the calendar month.
$\text{RTAML}_{q,\,p,i}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval *i*.
q	none	A QSE.
p	none	A Settlement Point in the 2003 ERCOT CMZ.
i	none	A 15-minute Settlement Interval.
z	none	A 2003 ERCOT CMZ.

[NPRR1030 and NPRR1054: Insert applicable portions of Section 6.6.2.8 below upon system implementation:]

6.6.2.8 QSE DC Tie Export Load Ratio Share by Congestion Management Zone for a Month

(1) Each QSE's DC Tie Export DCMLRSZ by CMZ for a calendar month is calculated as follows:

$$\textbf{DCMLRSZ}_{q,\,z} = \max(0, \sum_{i} \sum_{p} \textbf{RTAMLDC}_{q,\,p,\,i}) \,/\, \textbf{MRTAMLLZTOT}_{z}$$

The above variables are defined as follows:

Variable	Unit	Description
$DCMLRSZ_{q,\,z}$	none	*DC Tie Exports Monthly Load Ratio Share Zonal per QSE*—The ratio share calculated for QSE *q* with DC Tie exports by CMZ *z* for the calendar month.
$RTAMLDC_{q,\,p,\,i}$	MWh	*Real-Time Adjusted Metered Load for DC Ties per Settlement Point per QSE*—The sum of the DC Tie AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval *i*.
$MRTAMLLZTOT_{z}$	MWh	*Monthly Real-Time Adjusted Metered Load - Load Zone Total*—The total AML in CMZ z, for the calendar month.
q	none	A QSE.
p	none	A Settlement Point in the 2003 ERCOT CMZ.
i	none	A 15-minute Settlement Interval.
z	none	A 2003 ERCOT CMZ.

6.6.3 Real-Time Energy Charges and Payments

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

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

(a) The energy produced by all its Generation Resources, consumed as WSL, or consumed as Non-WSL ESR Charging Load at the Settlement Point; plus

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

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

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

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

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

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

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

$$\mathbf{RTEIAMT}_{q,p} = \mathbf{(-1) * \{ \sum_{gsc} (\sum_{r} (RESREV_{q,r,gsc,p})) + (\sum_{r} WSLAMTTOT_{q,r,p}) + (\sum_{r} ESRNWSLAMTTOT_{q,r,p}) + RTSPP_{p} * [(SSSK_{q,p} * \frac{1}{4}) + (DAEP_{q,p} * \frac{1}{4}) + (RTQQEP_{q,p} * \frac{1}{4}) - (SSSR_{q,p} * \frac{1}{4}) - (DAES_{q,p} * \frac{1}{4}) - (RTQQES_{q,p} * \frac{1}{4})]\}}$$

Where:

$$RESREV_{q,r,gsc,p} = GSPLITPER_{q,r,gsc,p} * NMSAMTTOT_{gsc}$$

$$RESMEB_{q,r,gsc,p} = GSPLITPER_{q,r,gsc,p} * NMRTETOT_{gsc}$$

$$WSLTOT_{q,p} = \sum_{r} (\sum_{b} MEBL_{q,r,b})$$

$$ESRNWSLTOT_{q,p} = \sum_{r} (\sum_{b} MEBR_{q,r,b})$$

$$RNIMBAL_{q,p} = \sum_{gsc} (\sum_{r} RESMEB_{q,r,gsc,p}) + WSLTOT_{q,p} + ESRNWSLTOT_{q,p} + (SSSK_{q,p} * \frac{1}{4}) + (DAEP_{q,p} * \frac{1}{4}) + (RTQQEP_{q,p} * \frac{1}{4}) - (SSSR_{q,p} * \frac{1}{4}) - (DAES_{q,p} * \frac{1}{4}) - (RTQQES_{q,p} * \frac{1}{4})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$RTEIAMT_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
$RNIMBAL_{q,p}$	MWh	*Resource Node Energy Imbalance per QSE per Settlement Point*—The Resource Node volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
$SSSK_{q,p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
$DAEP_{q,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
$RTQQEP_{q,p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
$SSSR_{q,p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.

Variable	Unit	Description
DAES $_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
RESREV $_{q, r, gsc, p}$	$	*Resource Share Revenue Settlement Payment*—The Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*.
RESMEB $_{q, r, gsc, p}$	MWh	*Resource Share Net Meter Real-Time Energy Total*—The Resource share of the net sum for all Settlement Meters attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*.
WSLTOT $_{q, p}$	MWh	*WSL Total*—The total WSL energy metered by the Settlement Meters which measure WSL for the QSE *q* at Settlement Point *p*.
ESRNWSLTOT $_{q, p}$	MWh	*ESR Non-WSL Total*—The total energy metered by the Settlement Meters which measures Non-WSL ESR Charging Load for the QSE *q* at Settlement Point *p.*
MEBL $_{q,r,b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBR $_{q, r, b}$	MWh	*Metered Energy for Energy Storage Resource Load at Bus*—The energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
NMSAMTTOT $_{gsc}$	$	*Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement.
WSLAMTTOT $_{q, r, p}$	$	*Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval.
ESRNWSLAMTTOT $_{q, r, p}$	$	*Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval.
NMRTETOT $_{gsc}$	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
GSPLITPER $_{q, r, gsc, p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a net metering arrangement. GSPLITPER is calculated by taking the Supervisory Control and Data Acquisition (SCADA) values (GSSPLITSCA) for a particular Generation Resource *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
p	none	A Resource Node Settlement Point.

Variable	Unit	Description
r	none	A Generation Resource or a Controllable Load Resource that is part of an ESR that is located at the Facility with net metering.
gsc	none	A generation site code.
b	none	An Electrical Bus.

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

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

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

Where:

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

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

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

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

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

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTEIAMT}_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
$\text{RNIMBAL}_{q,p}$	MWh	*Resource Node Energy Imbalance per QSE per Settlement Point*—The Resource Node volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.

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

NMRTETOT $_{gsc}$	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
GSPLITPER $_{q,\ r,\ gsc,\ p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a net metering arrangement. GSPLITPER is calculated by taking the Supervisory Control and Data Acquisition (SCADA) values (GSSPLITSCA) for a particular Generation Resource or ESR *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource or ESR that is located at the Facility with net metering.
gsc	none	A generation site code.
b	none	An Electrical Bus.

(3) For a facility with Settlement Meters that measure ESR Load, the total payment or charge for ESR Load is calculated for a QSE, ESR, and Settlement Point for each 15-minute Settlement Interval.

The WSL is settled as follows:

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

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

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

Where the price for Settlement Meter is determined as follows:

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

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

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

$$\textbf{[}\sum_{y} \textbf{Max (0.001, }\sum_{r} \textbf{BP}_{r,\,y}\textbf{) * TLMP}_{y}\textbf{]}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

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

The above variables are defined as follows:

Variable	**Unit**	**Description**
$\text{RTLMP}_{b,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{MEBL}_{q,r,b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
$\text{MEBR}_{q,\,r,\,b}$	MWh	*Metered Energy for Energy Storage Resource Load at Bus* - The energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
$\text{WSLAMTTOT}_{q,\,r,\,p}$	\$	*Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval.
$\text{ESRNWSLAMTTOT}_{q,\,r,\,p}$	\$	*Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval.

Variable	Unit	Description
$\text{RNWFL}_{b,\,y}$	none	*Net meter Weighting Factor per interval for the Energy Metered as Energy Storage Resource Load* —The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*, for the ESR Load associated with an ESR. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
RTRMPRESR_{b}	\$/MWh	*Real-Time Price for the Energy Metered as Energy Storage Resource Load at bus*—The Real-Time price for the Settlement Meter which measures ESR Load at Electrical Bus *b*, for the 15-minute Settlement Interval.
$\text{BP}_{r,\,y}$	MW	*Base Point per Resource per interval* - The Base Point of Resource *r*, for the SCED interval *y*.
q	none	A QSE.
gsc	none	A generation site code.
r	none	The Controllable Load Resource that is part of an ESR.
p	none	A Resource Node Settlement Point.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

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

(3) For a facility with Settlement Meters that measure ESR Load, the total payment or charge for ESR Load is calculated for a QSE, ESR, and Settlement Point for each 15-minute Settlement Interval.

The WSL is settled as follows:

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

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

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

Where the price for Settlement Meter is determined as follows:

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

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

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

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

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

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

The above variables are defined as follows:

Variable	**Unit**	**Description**
$\text{RTLMP}_{b,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA_{y}	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Real-Time Reliability Deployment price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{MEBL}_{q,r,b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
$\text{MEBR}_{q,r,b}$	MWh	*Metered Energy for Energy Storage Resource Load at Bus* - The energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
$\text{WSLAMTTOT}_{q,r,p}$	\$	*Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval.
$\text{ESRNWSLAMTTOT}_{q,r,p}$	\$	*Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval.

RNWFL $_{b,\,y}$	none	*Net meter Weighting Factor per interval for the Energy Metered as Energy Storage Resource Load* —The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*, for the ESR Load associated with an ESR. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
RTRMPRESR $_{b}$	$/MWh	*Real-Time Price for the Energy Metered as Energy Storage Resource Load at bus*—The Real-Time price for the Settlement Meter which measures ESR Load at Electrical Bus *b*, for the 15-minute Settlement Interval.
BP $_{r,\,y}$	MW	*Base Point per Resource per interval* - The Base Point of Resource *r*, for the SCED interval *y*.
q	none	A QSE.
gsc	none	A generation site code.
r	none	An ESR.
p	none	A Resource Node Settlement Point.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

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

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

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

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

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

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

Where the price for Settlement Meter is determined as follows:

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

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

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

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

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

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

The above variables are defined as follows:

Variable	Unit	Description
NMRTETOT_{gsc}	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
NMSAMTTOT_{gsc}	$	*Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement.
RTRMPR_{b}	$/MWh	*Real-Time Price for the Energy Metered for each Resource meter at bus*—The Real-Time price for the Settlement Meter at Electrical Bus *b*, for the 15-minute Settlement Interval.
$\text{MEB}_{gsc,\,b}$	MWh	*Metered Energy at bus*— The metered energy by the Settlement Meter which is not upstream from another Settlement Meter which measures ESR Load for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy withdrawn.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTLMP}_{b,\,y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.

Variable	Unit	Description
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RNWF $_{b,\,y}$	none	*Net meter Weighting Factor per interval*—The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
BP $_{r,\,y}$	MW	*Base Point per Resource per interval*—The Base Point of Resource *r,* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MEBC $_{gsc,\,b}$	MWh	*Metered Energy at bus (Calculated)*— The calculated energy for the 15-minute Settlement Interval for a Settlement Meter which is upstream from another Settlement Meter which measures ESR Load. A positive value represents energy produced, and a negative value represents energy withdrawn.
gsc	none	A generation site code.
r	none	A Generation Resource that is located at the Facility with net metering.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

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

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

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

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

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

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

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

Where the price for Settlement Meter is determined as follows**:**

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

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

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

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

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

The above variables are defined as follows:

Variable	**Unit**	**Description**
NMRTETOT_{gsc}	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
NMSAMTTOT_{gsc}	$	*Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement.
RTRMPR_{b}	$/MWh	*Real-Time Price for the Energy Metered for each Resource meter at bus*—The Real-Time price for the Settlement Meter at Electrical Bus *b*, for the 15-minute Settlement Interval.
$\text{MEB}_{gsc,b}$	MWh	*Metered Energy at bus*—The metered energy by the Settlement Meter which is not upstream from another Settlement Meter which measures ESR Load for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy withdrawn.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA_{y}	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.

RTLMP $_{b, y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RNWF $_{b, y}$	none	*Net meter Weighting Factor per interval*—The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
BP $_{r, y}$	MW	*Base Point per Resource per interval*—The Base Point of Resource *r,* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MEBC $_{gsc, b}$	MWh	*Metered Energy at bus (Calculated)* — The calculated energy for the 15-minute Settlement Interval for a Settlement Meter which is upstream from another Settlement Meter which measures ESR Load. A positive value represents energy produced, and a negative value represents energy withdrawn.
gsc	none	A generation site code.
r	none	A Generation Resource or ESR that is located at the Facility with net metering.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

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

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

The above variables are defined as follows:

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

Variable	Unit	Definition
r	none	A Generation Resource that is located at the Facility with net metering.
q	none	A QSE.
p	none	A Resource Node Settlement Point.

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

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

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

The above variables are defined as follows:

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

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

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

The above variables are defined as follows:

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

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

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

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

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

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

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

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

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

(g) Its AML at the Settlement Point excluding Non-WSL ESR Charging Load; plus

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

(i) The aggregated generation of its Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that have elected to retain Load Zone pricing in accordance with Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG). SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.

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

(i) The aggregated generation of its Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that have elected to retain Load Zone pricing in accordance with Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS). SODG, SOTG, Settlement Only Distribution Energy Storage System (SODESS), and Settlement Only Transmission Energy Storage System (SOTESS) sites will be represented as a single unit in the ERCOT Settlement system.

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

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

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \Big\{\Big[\mathbf{RTSPP}_{p} * [(\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4)]\Big] + \Big[\mathbf{RTSPPEW}_{p} * (\mathbf{RTMGSOGZ}_{q,p} - (\mathbf{RTAML}_{q,p} - \mathbf{RTAMLESRNW}_{q,p}))\Big]\Big\}$$

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

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \Big\{\Big[\mathbf{RTSPP}_{p} * [(\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4)]\Big] + \Big[\mathbf{RTSPPEW}_{p} * (\mathbf{RTMGSOGZ}_{q,p} - (\mathbf{RTAML}_{q,p} - \mathbf{RTAMLESRNW}_{q,p} - \mathbf{RTAMLNWSOL}_{q,p}))\Big]\Big\}$$

And

$$\mathbf{LZIMBAL}_{q,p} = (\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4) - (\mathbf{RTAML}_{q,p} - \mathbf{RTAMLESRNW}_{q,p}) + \mathbf{RTMGSOGZ}_{q,p}$$

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

$$\mathbf{LZIMBAL}_{q,\,p} = \mathbf{(SSSK}_{q,\,p}\ \mathbf{*\ \tfrac{1}{4})} + \mathbf{(DAEP}_{q,\,p}\ \mathbf{*\ \tfrac{1}{4})} + \mathbf{(RTQQEP}_{q,\,p}\ \mathbf{*\ \tfrac{1}{4})} - \mathbf{(SSSR}_{q,\,p}\ \mathbf{*\ \tfrac{1}{4})} - \mathbf{(DAES}_{q,\,p}\ \mathbf{*\ \tfrac{1}{4})} - \mathbf{(RTQQES}_{q,\,p}\ \mathbf{*\ \tfrac{1}{4})} - \mathbf{(RTAML}_{q,\,p} - \mathbf{RTAMLESRNW}_{q,\,p} - \mathbf{RTAMLNWSOL}_{q,\,p}\mathbf{)} + \mathbf{RTMGSOGZ}_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Description
RTEIAMT $_{q,\,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
LZIMBAL $_{q,\,p}$	MWh	*Load Zone Energy Imbalance per QSE per Settlement Point*—The Load Zone volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPPEW $_{p}$	$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the State Estimated Load for the Load Zone of each SCED interval within the 15-minute Settlement Interval.
RTAML $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval.
RTAMLESRNW $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load for ESR Non-WSL per QSE per Settlement Point*—The sum of the AML for the Non-WSL ESR Charging Load at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.

[NPRR995: Insert the variable "RTAMLNWSOL $_{q,\,p}$" below upon system implementation:]

RTAMLNWSOL $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load for Non-WSL Settlement Only Charging Load per QSE per Settlement Point*—The sum of the AML for the Non-WSL Settlement Only Charging Load for the SODESS or SOTESS site that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.

Variable	Unit	Description
SSSK $_{q,\,p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
DAEP $_{q,\,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q,\,p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.

Variable	Unit	Description
SSSR $_{q,\,p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
DAES $_{q,\,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q,\,p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
RTMGSOGZ $_{q,\,p}$	MWh	*Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by SOTSGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for ESS SODGs and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that have opted out of nodal pricing pursuant to Section 6.6.3.9 will also be included in this value.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

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

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

The above variables are defined as follows:

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

6.6.3.3 Real-Time Energy Imbalance Payment or Charge at a Hub

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

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

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

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

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

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

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

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

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \mathbf{RTSPP}_{p} * \left\{(\mathbf{SSSK}_{q,p} * \tfrac{1}{4}) + (\mathbf{DAEP}_{q,p} * \tfrac{1}{4}) + (\mathbf{RTQQEP}_{q,p} * \tfrac{1}{4}) - (\mathbf{SSSR}_{q,p} * \tfrac{1}{4}) - (\mathbf{DAES}_{q,p} * \tfrac{1}{4}) - (\mathbf{RTQQES}_{q,p} * \tfrac{1}{4})\right\}$$

And

$$\mathbf{HBIMBAL}_{q,p} = (\mathbf{SSSK}_{q,p} * \tfrac{1}{4}) + (\mathbf{DAEP}_{q,p} * \tfrac{1}{4}) + (\mathbf{RTQQEP}_{q,p} * \tfrac{1}{4}) - (\mathbf{SSSR}_{q,p} * \tfrac{1}{4}) - (\mathbf{DAES}_{q,p} * \tfrac{1}{4}) - (\mathbf{RTQQES}_{q,p} * \tfrac{1}{4})$$

The above variables are defined as follows:

Variable	Unit	Description
RTEIAMT $_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
HBIMBAL $_{q,p}$	MWh	*Hub Energy Imbalance per QSE per Settlement Point*—The Hub volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSK $_{q,p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
DAEP $_{q,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q,p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSR $_{q,p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.

Variable	Unit	Description
DAES $_{q,\,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*’s Energy Offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q,\,p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Hub Settlement Point.

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

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

The above variables are defined as follows:

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

6.6.3.4 Real-Time Energy Payment for DC Tie Import

(1) The payment to each QSE for energy imported into the ERCOT System through each DC Tie is calculated based on the Real-Time Settlement Point Price at the DC Tie Settlement Point. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCIMPAMT}_{q,\,p} = \textbf{(-1) * RTSPP}_{p} \textbf{ * (RTDCIMP}_{q,\,p} \textbf{ * ¼)}$$

The above variables are defined as follows:

Variable	Unit	Description
RTDCIMPAMT $_{q,\,p}$	$	*Real-Time DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
RTDCIMP $_{q,\,p}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval. ***[NPRR1032: Replace the description above with the following upon system implementation:]***

		Real-Time DC Import per QSE per Settlement Point—The aggregated final, approved DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(2) ERCOT shall pay each QSE for energy imported into the ERCOT System during a declared Emergency Condition through each DC Tie in response to an ERCOT Dispatch Instruction. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEDCIMPAMT}_{q,p} = (-1) * \mathbf{Max}\ \{\mathbf{RTSPP}_{p}, (\mathbf{VEEPDCTP}_{q,p} * \mathbf{CAEDCT})\} * (\mathbf{RTEDCIMP}_{q,p} * ¼)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTEDCIMPAMT $_{q,p}$	\$	*Real-Time Emergency DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for emergency DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
FIP	\$/MMBtu	*Fuel Index Price*—As defined in Section 2, Definitions and Acronyms.
RTEDCIMP $_{q,p}$	MW	*Real-Time Emergency DC Import per QSE per Settlement Point*—The aggregated DC Tie Schedule for emergency energy imported by QSE *q* into the ERCOT System during Emergency Conditions through DC Tie *p*, for the 15-minute Settlement Interval.
VEEPDCTP $_{q,p}$	\$/MWh	*Verified Emergency Energy Price at DC Tie Point*—The ERCOT verified cost for the energy imported by QSE *q* into the ERCOT System during declared Emergency Condition through a DC Tie *p* as instructed by a Dispatch Instruction.
CAEDCT	#	*Cost Adder for Emergency DC Tie Import*—A multiplier of 1.10.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(3) The total of the payments to each QSE for all energy imported into the ERCOT System through DC Ties for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTDCIMPAMTQSETOT}_{q,p} = \sum_{p} (\mathbf{RTDCIMPAMT}_{q,p} + \mathbf{RTEDCIMPAMT}_{q,p})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
RTDCIMPAMTQSETOT $_{q,p}$	\$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy imported into the ERCOT System through DC Ties *p,* for the 15-minute Settlement Interval.

Variable	**Unit**	**Definition**
RTDCIMPAMT $_{q,\, p}$	$	*Real-Time DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
RTEDCIMPAMT $_{q,\, p}$	$	*Real-Time Emergency DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for emergency DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

6.6.3.5 Real-Time Payment for a Block Load Transfer Point

(1) ERCOT shall pay each QSE for the energy delivered to an ERCOT Load through a Block Load Transfer (BLT) Point that is registered for Settlement when that Load is moved from the ERCOT Control Area to a non-ERCOT Control Area. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{BLTRAMT}_{q,\, bltp,\, p} = (-1) * \mathbf{MAX}\ \{\mathbf{RTSPPEW}_{p}, (\mathbf{VEEPBLTP}_{q,\, bltp}) * \mathbf{CABLT}\} * \mathbf{BLTR}_{q,\, p,\, bltp}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
BLTRAMT $_{q,\, bltp,\, p}$	$	*Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point*—The payment to QSE *q* for the BLT Resource that delivers energy to Load Zone *p* through BLT Point *bltp*, for the 15-minute Settlement Interval.
RTSPPEW $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point Energy-Weighted*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval, that is weighted by the state estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Internal.
VEEPBLTP $_{q,\, bltp}$	$/MWh	*Verified Emergency Energy Price at BLT Point*—The ERCOT verified cost for the energy delivered to an ERCOT Load through BLT Point *bltp*.
CABLT	none	*Cost Adder for Block Load Transfer*—A multiplier of 1.10.
BLTR $_{q,\, p,\, bltp}$	MWh	*Block Load Transfer Resource per QSE per Settlement Point per BLT Point*—The energy delivered to an ERCOT Load in Load Zone *p* through BLT Point *bltp* represented by QSE *q*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.

(2) The total of the payments to each QSE for all energy delivered to ERCOT Loads through BLT Points for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{BLTRAMTQSETOT}_{q} = \sum_{p} \sum_{bltp} \textbf{BLTRAMT}_{q,\, bltp,\, p}$$

The above variables are defined as follows:

Variable	Unit	Definition
BLTRAMTQSETOT $_{q}$	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT System through BLT Points for the 15-minute Settlement Interval.
BLTRAMT $_{q,\, bltp,\, p}$	$	*Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point*—The payment to QSE *q* for the BLT Resource at BLT Point *bltp*, which delivers energy to Load Zone *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.

(3) For the purpose of Settlement, ERCOT shall treat the energy associated with the Presidio Exception like energy delivered to an ERCOT Load through a BLT Point that is moved from the ERCOT Control Area to a non-ERCOT Control Area, by allowing for compensation of verified costs associated with the energy. After receipt and verification of the invoiced cost associated with the Presidio Exception, ERCOT shall compensate for the energy associated with the Presidio Exception using the monthly verified cost multiplied by the Cost Adder for Block Load Transfer defined in paragraph (1) above. ERCOT shall uplift the cost to QSEs representing Load using the monthly LRS per QSE as defined in Section 7.5.7, Method for Distributing CRR Auction Revenues. Costs associated with the Presidio Exception must be submitted to ERCOT within 90 days of the last day of the month that the costs were incurred.

[NPRR1030: Replace paragraph (3) above with the following upon system implementation:]

(3) For the purpose of Settlement, ERCOT shall treat the energy associated with the Presidio Exception like energy delivered to an ERCOT Load through a BLT Point that is moved from the ERCOT Control Area to a non-ERCOT Control Area, by allowing for compensation of verified costs associated with the energy. After receipt and verification of the invoiced cost associated with the Presidio Exception, ERCOT shall compensate for the energy associated with the Presidio Exception using the monthly verified cost multiplied by the Cost Adder for Block Load Transfer defined in paragraph (1) above. ERCOT shall uplift the cost to QSEs representing Load using the same methodology as defined in Section 7.5.7, Method for Distributing CRR Auction Revenues. Costs associated with the Presidio Exception must be submitted to ERCOT within 90 days of the last day of the month that the costs were incurred.

(a) The monthly payment to be calculated as follows:

$$\textbf{MBLTAMT}_{q,\, p} = (-1) * \textbf{VMEBLTP}_{q,\, p} * \textbf{CABLT}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$MBLTAMT_{q,\,p}$	$	*Monthly Block Load Transfer Amount per QSE per Settlement Point*—The payment to QSE *q* for the delivered energy to Load Zone *p* for the month.
$VMEBLTP_{q,\,p}$	$/MWh	*Verified Monthly Energy Cost*—The ERCOT verified monthly cost for the energy delivered to an ERCOT Load as determined by an invoice submitted to ERCOT.
CABLT	none	*Cost Adder for Block Load Transfer*—A multiplier of 1.10.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

(b) The total of the payments to each QSE for all energy delivered to ERCOT Loads through BLT Points for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{MBLTAMTQSETOT}_{q} = \sum_{p} \mathbf{MBLTAMT}_{q,\,p}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$MBLTAMTQSETOT_{q}$	$	*Monthly Block Load Transfer Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT System for the month.
$MBLTAMT_{q,\,p}$	$	*Monthly Block Load Transfer Amount per QSE per Settlement Point*—The payment to QSE *q* for the delivered energy to Load Zone *p* for the month.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

(c) ERCOT shall calculate each QSE’s monthly BLT charge as follows:

$$\mathbf{LAMBLTAMT}_{q} = (-1) * \mathbf{MLRS}_{q} * \mathbf{MBLTAMTTOT}$$

$$\mathbf{MBLTAMTTOT} = \sum_{q} \mathbf{MBLTAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$MLRS_{q}$	none	*Monthly Load Ratio Share per QSE*—The LRS calculated for QSE *q* for the peak-Load 15-minute Settlement Interval in the month. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
$MBLTAMTQSETOT_{q}$	$	*Monthly Block Load Transfer Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT System for the month.
$LAMBLTAMT_{q}$	$	*Load-Allocated Monthly BLT Amount per QSE*—Monthly BLT charge for QSE *q*.
MBLTAMTTOT	$	*Monthly BLT Amount ERCOT wide Total*—The total monthly BLT charge for all QSEs.
q	none	A QSE.

[NPRR1030 and NPRR1054: Replace applicable portions of paragraph (c) above with the following upon system implementation:]

(c) ERCOT shall calculate each QSE's monthly BLT charge as follows:

$$\mathbf{LAMBLTAMT}_{q} = \mathbf{(-1) * (MBLTDC}_{q} \mathbf{+ MBLTNDC}_{q}\mathbf{)}$$

Where:

$$\text{MBLTNDC}_{q} = \text{MLRS}_{q} * (\text{MBLTAMTTOT} - \sum_{q} \text{MBLTDC}_{q})$$

$$\text{MBLTDC}_{q} = \text{DCMLRS}_{q} * \text{MBLTAMTTOT}$$

$$\text{MBLTAMTTOT} = \sum_{q} \text{MBLTAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
LAMBLTAMT $_{q}$	$	*Load-Allocated Monthly BLT Amount per QSE*—Sum of the monthly BLT charges for Loads and DC Tie exports for QSE *q*.
DCMLRS $_{q}$	none	*DC Tie Export Monthly Load Ratio Share per QSE*—The ratio share calculated for QSE *q* with DC Tie Exports for the calendar month.
MLRS $_{q}$	none	*Monthly Load Ratio Share per QSE*—The ratio share of Loads excluding DC Tie Exports for QSE *q,* for the peak Load 15-minute Settlement Interval.
MBLTAMTQSETOT $_{q}$	$	*Monthly Block Load Transfer Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT System for the month.
MBLTDC $_{q}$	$	*Monthly BLT Amount for DC Tie Exports per QSE*—Monthly BLT amount for DC Tie exports for QSE *q*.
MBLTNDC $_{q}$	$	*Monthly BLT Amount for Non-DC Tie Loads per QSE*—Monthly BLT amount for Loads (excluding DC Tie exports) for QSE *q*.
MBLTAMTTOT	$	*Monthly BLT Amount ERCOT wide Total*—The total monthly BLT payment for all QSEs.
q	none	A QSE.

6.6.3.6 Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption

(1) The charge to a QSE that is exporting energy from the ERCOT System under the "Oklaunion Exemption" through a DC Tie associated with the exemption is calculated based on the Real-Time Settlement Point Price at the DC Tie Settlement Point. This charge for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCEXPAMT}_{q,\,p} \quad = \quad \textbf{RTSPP}_{p} * (\textbf{RTDCEXP}_{q,\,p} * \tfrac{1}{4})$$

The above variables are defined as follows:

Variable	Unit	Definition
RTDCEXPAMT $_{q,\,p}$	$	*Real-Time DC Export Amount per QSE per Settlement Point*—The charge to QSE *q* for the DC Tie exports through DC Tie *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
RTDCEXP $_{q,\,p}$	MW	*Real-Time DC Export per QSE per Settlement Point*—The aggregated DC Tie Schedule through DC Tie *p* submitted by QSE *q* that is under the "Oklaunion Exemption" as an exporter from the ERCOT area, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(2) The total of the charges to each QSE for all energy exported from the ERCOT System through DC Ties for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCEXPAMTQSETOT}_{q} \quad = \quad \sum_{p} \textbf{RTDCEXPAMT}_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTDCEXPAMTQSETOT $_{q}$	$	*Real-Time DC Export Amount QSE Total per QSE*—The total of the charges to QSE *q* for energy exported from the ERCOT System through DC Ties for the 15-minute Settlement Interval.
RTDCEXPAMT $_{q,\,p}$	$	*Real-Time DC Export Amount per QSE per Settlement Point*—The charge to QSE *q* for the DC Tie exports through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

[NPRR1054: Delete Section 6.6.3.6 above upon system implementation and renumber accordingly.]

6.6.3.7 Real-Time High Dispatch Limit Override Energy Payment

(1) If ERCOT directs a reduction in a Generation Resource's real power output by employing a manual High Dispatch Limit (HDL) override and the reduction causes the QSE to suffer a demonstrable financial loss, the QSE may be eligible for a Real-Time High Dispatch Limit Override Energy Payment, as calculated below, upon providing documented proof of that loss. In order to qualify for this payment the QSE must:

(a) Have complied with ERCOT Dispatch Instructions to reduce real power output;

(b) Have received a SCED Base Point equal to the Resource's HDL override, during the 15-minute Settlement Interval;

(c) Have incurred a demonstrable financial loss associated with variable cost components of DAM obligations or energy purchase or sale provisions of bilateral contracts (as opposed to lost opportunity costs), in consequence of the HDL override; and

(d) File a timely Settlement and billing dispute, including the following items:

(i) An attestation signed by an officer or executive with authority to bind the QSE;

(ii) The dollar amount and calculation of the financial loss by Settlement Interval;

(iii) An explanation of the nature of the loss and how it was attributable to the HDL override; and

(iv) Sufficient documentation to support the QSE's calculation of the amount of the financial loss.

(2) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 business days of ERCOT's request. ERCOT will provide Notice of its acceptance or rejection of the claim for the High Dispatch Limit Override Energy Payment within 15 Business Days of the updated submission.

(3) The Energy Offer Curve used to calculate the Real-Time High Dispatch Limit Override Energy Payment will be the most recent valid Energy Offer Curve received by ERCOT that was effective for the disputed interval(s) when the HDL override was issued. If no curve exists for the interval being disputed, ERCOT will use the most recent valid Energy Offer Curve received before the HDL override was issued for an interval prior to the disputed interval(s).

The payment shall be calculated as follows:

$$\mathbf{HDLOEAMT}_{q,r,p,i} = \mathbf{(-1) * Min \{HDLOAL}_{q,r,p,i}\mathbf{, Max(0, ((RTSPP}_{p,i}\mathbf{ - RTRSVPOR}_{i}\mathbf{ - RTRDP}_{i}\mathbf{ - RTEOCOST}_{q,r,i}\mathbf{) * HDLOQTY}_{q,r,p,i}\mathbf{))\}}$$

Where:

$$\text{HDLOQTY}_{q,r,p,i} = \text{Max}(0, (\tfrac{1}{4} (\text{HDLOBRKP}_{q,r,p,i} - \text{AVGHDL}_{q,r,p,i})))$$

$$\text{HDLOBRKP}_{q,r,p,i} = \text{Min}(\text{AVGHASL}_{q,r,p,i}, \text{HDLOBRKPCP}_{q,r,p,i})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
HDLOAL $_{q, r, p, i}$	$	*High Dispatch Limit override attested losses* - The financial loss to the QSE due to the HDL override as attested by the QSE in accordance with paragraph (1)(d) above.
HDLOEAMT $_{q, r, p, i}$	$	*High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
HDLOBRKP $_{q, r, p, i}$	MW	*High Dispatch Limit override break point per QSE per Resource*—The point on the Energy Offer Curve corresponding to the lesser of the AVGHASL or the interception between the RTSPP of the Generation Resource *r* represented by QSE *q* minus the Real-Time Reserve Price for On-Line Reserves and the Real-Time On-Line Reliability Deployment Price and the Energy Offer Curve of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
AVGHDL $_{q, r, p, i}$	MW	*Average High Dispatch Limit per QSE per Settlement Point per Resource*—The time-weighted average of all 4-second HDL values calculated by the Resource Limit Calculator, subject to the manual HDL override, for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
AVGHASL $_{q, r, p, i}$	MW	*Average High Ancillary Service Limit per QSE per Settlement Point per Resource*—The time-weighted average High Ancillary Service Limit (HASL) calculated every four seconds by the Resource Limit Calculator for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
HDLOBRKPCP $_{q, r, p, i}$	MW	*High Dispatch Limit override break point at clearing price per QSE per Resource*—The MW value on the Energy Offer Curve corresponding to the Real-Time Settlement Point Price of Generation Resource *r* represented by QSE *q* at Settlement Point *p* minus the Real-Time Reserve Price for On-Line Reserves and the Real-Time On-Line Reliability Deployment Price. For a combined cycle Resource, *r* is a Combined Cycle Train.
RTEOCOST $_{q, r, i}$	$/MWh	Real-Time Energy Offer Curve Cost Cap - The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
HDLOQTY $_{q, r, p, i}$	MWh	*High Dispatch Limit override quantity per QSE per Generation Resource*— The difference between the HDLOBRKP and the AVGHDL due to an ERCOT-issued HDL override for Generation Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
RTRSVPOR $_{i}$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
RTRDP $_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.

Variable	Unit	Definition
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

(4) The total compensation to each QSE for an HDL override for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{HDLOEAMTQSETOT}_{q,\,i} = \sum_{r} \sum_{p} \textbf{HDLOEAMT}_{q,\,r,\,p,\,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
HDLOEAMT $_{q,\,r,\,p,\,i}$	$	*High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
HDLOEAMTQSETOT $_{q,\,i}$	$	*High Dispatch Limit override energy amount QSE total per QSE*—The total of the energy payments to QSE *q* as compensation for HDL overrides for this QSE for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

[NPRR1010: Replace Section 6.6.3.7 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.6.3.7 Real-Time High Dispatch Limit Override Energy Payment

(1) If ERCOT directs a reduction in a Generation Resource’s real power output by employing a manual High Dispatch Limit (HDL) override and the reduction causes the QSE to suffer a demonstrable financial loss, the QSE may be eligible for a Real-Time High Dispatch Limit Override Energy Payment, as calculated below, upon providing documented proof of that loss. In order to qualify for this payment the QSE must:

(a) Have complied with ERCOT Dispatch Instructions to reduce real power output;

(b) Have received a SCED Base Point equal to the Resource’s HDL override, during the 15-minute Settlement Interval;

(c) Have incurred a demonstrable financial loss associated with variable cost components of DAM obligations or energy purchase or sale provisions of bilateral contracts (as opposed to lost opportunity costs), in consequence of the HDL override; and

(d) File a timely Settlement and billing dispute, including the following items:

(i) An attestation signed by an officer or executive with authority to bind the QSE;

(ii) The dollar amount and calculation of the financial loss by Settlement Interval;

(iii) An explanation of the nature of the loss and how it was attributable to the HDL override; and

(iv) Sufficient documentation to support the QSE's calculation of the amount of the financial loss.

(2) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT's request. ERCOT will provide Notice of its acceptance or rejection of the claim for the High Dispatch Limit Override Energy Payment within 15 Business Days of the updated submission.

(3) The Energy Offer Curve used to calculate the Real-Time High Dispatch Limit Override Energy Payment will be the most recent valid Energy Offer Curve received by ERCOT that was effective for the disputed interval(s) when the HDL override was issued. If no curve exists for the interval being disputed, ERCOT will use the most recent valid Energy Offer Curve received before the HDL override was issued for an interval prior to the disputed interval(s).

(4) The amount recoverable under this section shall be offset by any Ancillary Service Imbalance revenues received by the QSE that the QSE would not have earned had ERCOT not issued an HDL override.

The payment shall be calculated as follows:

$$\mathbf{HDLOEAMT}_{q,\,r,\,p,\,i} = \mathbf{(-1) * Min\ \{HDLOAL}_{q,\,r,\,p,\,i}\mathbf{,\ Max(0,\ ((RTSPP}_{p,\,i} - \mathbf{RTRDP}_{i} - \mathbf{RTEOCOST}_{q,\,r,\,i}\mathbf{)\ *\ HDLOQTY}_{q,\,r,\,p,\,i}\mathbf{))\}}$$

Where:

$\text{HDLOQTY}_{q,\,r,\,p,\,i} = \text{Max}(0, (¼\ (\text{HDLOBRKP}_{q,\,r,\,p,\,i} - \text{AVGHDL}_{q,\,r,\,p,\,i})))$

$\text{HDLOBRKP}_{q,\,r,\,p,\,i} = \text{Min}(\text{AVGHSL}_{q,\,r,\,p,\,i}, \text{HDLOBRKPCP}_{q,\,r,\,p,\,i})$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
HDLOAL $_{q, r, p, i}$	$	*High Dispatch Limit override attested losses* - The financial loss to the QSE due to the HDL override as attested by the QSE in accordance with paragraph (1)(d) above.
HDLOEAMT $_{q, r, p, i}$	$	*High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
HDLOBRKP$_{q, r, p, i}$	MW	*High Dispatch Limit override break point per QSE per Resource*—The point on the Energy Offer Curve corresponding to the lesser of the AVGHSL or the interception between the RTSPP of the Generation Resource *r* represented by QSE *q* minus the Real-Time Reliability Deployment Price for Energy and the Energy Offer Curve of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
AVGHDL$_{q, r, p, i}$	MW	*Average High Dispatch Limit per QSE per Settlement Point per Resource*—The time-weighted average of all 4-second HDL values calculated by the Resource Limit Calculator, subject to the manual HDL override, for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
AVGHSL $_{q, r, p, i}$	MW	*Average High Sustained Limit per QSE per Settlement Point per Resource*—The time-weighted average High Sustained Limit (HSL) for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
HDLOBRKPCP $_{q, r, p, i}$	MW	*High Dispatch Limit override break point at clearing price per QSE per Resource*—The MW value on the Energy Offer Curve corresponding to the Real-Time Settlement Point Price of Generation Resource *r* represented by QSE *q* at Settlement Point *p* minus the Real-Time Reliability Deployment Price for Energy. For a combined cycle Resource, *r* is a Combined Cycle Train.
RTEOCOST $_{q, r, i}$	$/MWh	*Real-Time Energy Offer Curve Cost Cap*—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource's generation above the Low Sustained Limit (LSL) for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
HDLOQTY $_{q, r, p, i}$	MWh	*High Dispatch Limit override quantity per QSE per Generation Resource*—The difference between the HDLOBRKP and the AVGHDL due to an ERCOT-issued HDL override for Generation Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.

$RTRDP_{i}$	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

(5) The total compensation to each QSE for an HDL override for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{HDLOEAMTQSETOT}_{q,\,i} = \sum_{r} \sum_{p} \mathbf{HDLOEAMT}_{q,\,r,\,p,\,i}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$HDLOEAMT_{q,\,r,\,p,\,i}$	\$	*High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
$HDLOEAMTQSETOT_{q,\,i}$	\$	*High Dispatch Limit override energy amount QSE total per QSE*—The total of the energy payments to QSE *q* as compensation for HDL overrides for this QSE for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

6.6.3.8 Real-Time High Dispatch Limit Override Energy Charge

(1) ERCOT shall allocate to QSEs on an LRS basis the total amount of the payment specified in Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Payment. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LAHDLOEAMT}_{q,\,i} = (-1) * \mathbf{HDLOEAMTTOT} * \mathbf{LRS}_{q,\,i}$$

Where:

$$HDLOEAMTTOT_{i} = \sum_{q} HDLOEAMTQSETOT_{q,\,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
LAHDLOPEAMT $_{q}$	$	*Load-Allocated High Dispatch Limit override energy amount per QSE*—The charge to QSE *q* for an HDL override, for the 15-minute Settlement Interval.
HDLOEAMTTOT $_{i}$	$	*High Dispatch Limit energy amount total*—The total of payments to all QSEs for HDL overrides, for the 15-minute Settlement Interval *i*.
HDLOEAMTQSETOT $_{q,\,i}$	$	*High Dispatch Limit override energy amount QSE total per QSE*—The total of the energy payments to QSE *q* as compensation for an HDL override for this QSE for the 15-minute Settlement Interval *i*.
LRS $_{q,\,i}$	none	*The Load Ratio Share* calculated for QSE *q* for the 15-minute Settlement Interval *i*. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
i	none	A 15-minute Settlement Interval.

6.6.3.9 Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG)

(1) The payment or charge to each QSE for energy from an SODG or an SOTG shall be based on an identified nodal energy price, RTESOGPR, as described in this subsection, with the following exceptions:

(a) An SODG or SOTG that has opted out of nodal pricing as described in paragraph (5) below; or

(b) Any site with one or more ESS SODGs or SOTGs where the ESS capacity constitutes more than 50% of the site's total SOG nameplate capacity.

(2) For an SODG, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus associated with this mapped Load in the Network Operations Model. For an SOTG, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus as determined by ERCOT in review of the meter location of the SOTG in the Network Operations Model. SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.

(3) For an SODG or an SOTG, the total payment or charge for each 15-minute Settlement Interval shall be calculated as follows:

$$\mathbf{MEBSOGNET}_{q,\,gsc} = \mathbf{Max(0,}\ \sum_{b} \mathbf{MEBSOG}_{q,\,gsc,\,b}\mathbf{)}$$

If MEBSOGNET $_{q,\,gsc}$ = 0 for a 15-minute Settlement Interval, then

The Load is included in the Real-Time AML per QSE and is included in the Real-Time energy imbalance payment or charge at a Load Zone.

Otherwise, when $\mathrm{MEBSOGNET}_{q,\,gsc} > 0$ for a 15-minute Settlement Interval, then

$$\mathbf{RTESOGSAMT}_{q,\,gsc} \quad = \quad \mathbf{(-1) * [\sum_{b} (RTESOGPR_{\mathit{b}} * MEBSOG_{\mathit{q,\,gsc,\,b}})]}$$

Where the price for the SOTG or SODG is determined as follows:

$$\mathbf{RTESOGPR}_{b} \; = \quad \mathbf{Max\ [-\$251,\ \sum_{y} ((SDWF_{\mathit{y}} * RTLMP_{\mathit{b,\,y}}) + RTRSVPOR + RTRDP)]}$$

Where:

$$\mathrm{RTRSVPOR} \quad = \quad \sum_{y} (\mathrm{SDWF}_{y} * \mathrm{RTORPA}_{y})$$

$$\mathrm{RTRDP} \quad = \quad \sum_{y} (\mathrm{SDWF}_{y} * \mathrm{RTORDPA}_{y})$$

$$\mathrm{SDWF}_{y} \quad = \quad \mathrm{TLMP}_{y} / \sum_{y} \mathrm{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\mathrm{RTESOGSAMT}_{q,\,gsc}$	$	*Real-Time Energy for SODG and SOTG Site Amount* —The total payment or charge to QSE *q* for SODG or SOTG site *gsc* for the 15-minute Settlement Interval.
$\mathrm{RTESOGPR}_{b}$	$/MWh	*Real-Time Price for the Energy Metered for each SODG or SOTG Site* —The Real-Time price at Electrical Bus *b* for the Settlement Meter for the SODG or SOTG site for the 15-minute Settlement Interval.
$\mathrm{MEBSOGNET}_{q,\,gsc}$	MWh	*Net Metered energy at gsc for an SODG or SOTG Site* —The net sum for all Settlement Meters for SODG or SOTG site *gsc* represented by QSE *q*. A positive value indicates an injection of power to the ERCOT System.
$\mathrm{MEBSOG}_{q,\,gsc,\,b}$	MWh	*Metered energy at bus for an SODG or SOTG Site* —The metered energy by the Settlement Meter(s) at Electrical Bus *b* for SODG or SOTG site *gsc* represented by QSE *q*. A positive value represents energy produced, and a negative value represents energy consumed.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.

Variable	Unit	Description
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
SDWF_{y}	None	*SCED Duration Weighting Factor per interval*—The weight used in the SODG or SOTG price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTLMP}_{b,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus *b*, for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y* within the Settlement Interval.
gsc	none	A generation site code.
b	none	An Electrical Bus.
y	None	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

(4) The total net payments and charges to each QSE for energy from SODGs and SOTGs for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTESOGAMTQSETOT}_{q} = \sum_{gsc} \textbf{RTESOGSAMT}_{q,\,gsc}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RTESOGAMTQSETOT}_{q}$	\$	*Real-Time Energy Payment or Charge per QSE for Energy from SODGs and SOTGs* —The payment or charge to QSE *q* for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval.
$\text{RTESOGSAMT}_{q,\,gsc}$	\$	*Real-Time Energy for SODG and SOTG Site Amount* —The total payment or charge to QSE *q* for an SODG or SOTG site *gsc* for the 15-minute Settlement Interval.
q	none	A QSE.
gsc	none	A generation site code.

(5) Notwithstanding anything else in this Section except paragraphs (6) and (7) below, a Resource Entity may opt out of nodal pricing and continue Load Zone Settlement for any SODG or SOTG if, by January 1, 2019, the SODG or SOTG was operational or was subject to a Power Purchase or Tolling Agreement (PPA) or Transmission and/or Distribution Service Provider (TDSP) interconnection agreement, or had an executed agreement with a developer. By December 31, 2019, the Resource Entity must submit a properly completed Section 23, Form N, Pricing Election for Settlement Only Distribution Generators and Settlement Only Transmission Generators. Any SODG or SOTG relying on a PPA or TDSP interconnection agreement or agreement with a developer must also have achieved Initial Synchronization for the full Resource capacity before June 1, 2020 to be eligible to opt out of nodal pricing. A Resource Entity must provide ERCOT documented proof of any PPA, TDSP interconnection agreement, or developer agreement that it relies on as a basis for any election under this paragraph. This election is valid through the earlier of December 31, 2029 or the date on which the

election is revoked pursuant to paragraph (8) of this Section. On January 1, 2030, all SODGs and SOTGs will be subject to nodal pricing.

(6) For any SODG or SOTG for which the applicable Resource Entity has elected to opt out of nodal pricing, ERCOT shall settle the output of the SODG or SOTG using the Load Zone Settlement Point Price for the duration of the opt-out period so long as the SODG or SOTG is not physically modified for any purpose, including to increase the capacity of the unit or change the fuel type of the unit, except as necessary for routine maintenance or repairs to address normal wear and tear.

(7) If at any time ERCOT determines that the SODG or SOTG fails to meet the opt-out conditions in paragraph (6) above, ERCOT shall settle the output of the SODG or SOTG at the applicable nodal price as soon as practicable after providing written notice to the affected Resource Entity.

(8) A Resource Entity that has opted out of nodal pricing for one or more SODGs or SOTGs pursuant to paragraph (5) of this Section may withdraw that election and begin receiving applicable nodal pricing for one or more such generators by submitting a properly completed election form (Section 23, Form N). An election of nodal pricing is irrevocable. ERCOT will effectuate the transition of an SODG or SOTG to nodal pricing in ERCOT Settlement systems as soon as practicable.

[NPRR995 and NPRR1010: Replace applicable portions of Section 6.6.3.9 above with the following upon system implementation for NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.3.9 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)

(1) The payment or charge to each QSE for energy from an SODG, SOTG, SODESS, or SOTESS shall be based on an identified nodal energy price, RTESOPR, as described in this subsection, with the exception of an SODG or SOTG that has opted out of nodal pricing as described in paragraph (7) below.

(2) For an SODG or an SODESS, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus associated with this mapped Load in the Network Operations Model. For an SOTG or an SOTESS, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus as determined by ERCOT in review of the meter location of the SOTG or SOTESS in the Network Operations Model. Load that is not WSL will be included in the Real-Time AML per QSE. Each SODG, SOTG, SODESS, and SOTESS site will be represented as a single unit in the ERCOT Settlement system.

(3) For an SODG, SOTG, SODESS, or SOTESS, the total payment or charge for each 15-

minute Settlement Interval shall be calculated as follows:

$$\mathbf{MEBSOGNET}_{q,\,gsc} = \mathbf{Max(0,}\ \sum_{b} \mathbf{MEBSOG}_{q,\,gsc,\,b}\mathbf{)}$$

If MEBSOGNET $_{q,\,gsc}$ = 0 for a 15-minute Settlement Interval, then

The Load is included in the Real-Time AML per QSE, excluding WSL.

Otherwise, when MEBSOGNET $_{q,\,gsc}$ > 0 for a 15-minute Settlement Interval, then

$$\mathbf{RTGSOAMT}_{q,\,gsc} = \mathbf{(-1) * [}\sum_{b} \mathbf{(RTESOPR}_{b}\mathbf{ * MEBSOG}_{q,\,gsc,\,b}\mathbf{)]}$$

(4) For an SODESS or SOTESS, the total payment or charge for each 15-minute Settlement Interval shall be calculated as follows:

$$\mathbf{RTWSLSOAMT}_{q,\,gsc} = \mathbf{(-1) * [}\sum_{b} \mathbf{(RTESOPR}_{b}\mathbf{ * WSOL}_{q,\,gsc,\,b}\mathbf{)]}$$

$$\mathbf{RTNWSLSOAMT}_{q,\,gsc} = \mathbf{(-1) * [}\sum_{b} \mathbf{(RTESOPR}_{b}\mathbf{ * NWSOL}_{q,\,gsc,\,b}\mathbf{)]}$$

(5) The price for the SOTG, SODG, SODESS, or SOTESS is determined as follows:

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

Where:

$$\text{RTRDP} = \sum_{y} (\text{SDWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{SDWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTGSOAMT $_{q,\,gsc}$	$	*Real-Time Generation for SODG, SOTG, SODESS, or SOTESS Site Amount* —The total payment or charge for generation to QSE *q* for SODG, SOTG, SODESS, or SOTESS site *gsc* for the 15-minute Settlement Interval.
RTWSLSOAMT $_{q,\,gsc}$	$	*Real-Time WSL for SODESS or SOTESS Site Amount* —The total payment or charge for WSL to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.
RTNWSLSOAMT $_{q,\,gsc}$	$	*Real-Time Non-WSL for SODESS or SOTESS Site Amount* —The total payment or charge for Non-WSL Settlement Only Charging Load to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.

$RTESOPR_{b}$	\$/MWh	*Real-Time Price for the Energy Metered for each SODG, SOTG, SODESS, or SOTESS Site* —The Real-Time price at Electrical Bus *b* for the Settlement Meter for the SODG, SOTG, SODESS, or SOTESS site for the 15-minute Settlement Interval.
$MEBSOGNET_{q,\ gsc}$	MWh	*Net Metered energy at gsc for an SODG, SOTG, SODESS or SOTESS Site* —The net sum for all Settlement Meters for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by QSE *q*. A positive value indicates an injection of power to the ERCOT System.
$MEBSOG_{q,\ gsc,\ b}$	MWh	*Metered energy at bus for an SODG, SOTG, SODESS, or SOTESS Site* —The metered energy by the Settlement Meter(s) at Electrical Bus *b* for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by QSE *q* for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy consumed.
$WSOL_{q,\ gsc,\ b}$	MWh	*WSL for an SODESS or SOTESS Site*—The WSL as measured for an SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by QSE *q,* represented as a negative value, for the 15-minute Settlement Interval.
$NWSOL_{q,\ gsc,\ b}$	MWh	*Non-WSL Settlement Only Charging Load for an SODESS or SOTESS Site*—The Non-WSL Settlement Only Charging Load as measured for an SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by QSE *q,* represented as a negative value, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$SDWF_{y}$	None	*SCED Duration Weighting Factor per interval* —The weight used in the SODG, SOTG, SODESS, or SOTESS price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RTLMP_{b,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval* —The Real-Time LMP at Electrical Bus *b*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval* —The duration of the SCED interval *y* within the Settlement Interval.
gsc	none	A generation site code.
b	none	An Electrical Bus.
y	None	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

(6) The total net payments and charges to each QSE for energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTESOAMTQSETOT}_{q} = \sum_{gsc} (\mathbf{RTGSOAMT}_{q,\ gsc} + \mathbf{RTWSLSOAMT}_{q,\ gsc} + \mathbf{RTNWSLSOAMT}_{q,\ gsc})$$

The above variables are defined as follows:

Variable	Unit	Definition
RTESOAMTQSETOT $_{q}$	$	*Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESSs, or SOTESSs* —The payment or charge to QSE *q* for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs, for the 15-minute Settlement Interval.
RTGSOAMT $_{q,\ gsc}$	$	*Real-Time Generation for SODG, SOTG, SODESS, or SOTESS Site Amount* —The total payment or charge for generation to QSE *q* for SODG, SOTG, SODESS, or SOTESS site *gsc* for the 15-minute Settlement Interval.
RTWSLSOAMT $_{q,\ gsc}$	$	*Real-Time WSL for SODESS or SOTESS Site Amount* —The total payment or charge for WSL to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.
RTNWSLSOAMT $_{q,\ gsc}$	$	*Real-Time Non-WSL for SODESS or SOTESS Site Amount* —The total payment or charge for Non-WSL Settlement Only Charging Load to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.
q	none	A QSE.
gsc	none	A generation site code.

(7) Notwithstanding anything else in this Section except paragraphs (8) and (9) below, a Resource Entity may opt out of nodal pricing and continue Load Zone Settlement for any SODG or SOTG if, by January 1, 2019, the SODG or SOTG was operational or was subject to a Power Purchase or Tolling Agreement (PPA) or Transmission and/or Distribution Service Provider (TDSP) interconnection agreement, or had an executed agreement with a developer. By December 31, 2019, the Resource Entity must submit a properly completed Section 23, Form N, Pricing Election for Settlement Only Distribution Generators and Settlement Only Transmission Generators. Any SODG or SOTG relying on a PPA or TDSP interconnection agreement or agreement with a developer must also have achieved Initial Synchronization for the full Resource capacity before June 1, 2020 to be eligible to opt out of nodal pricing. A Resource Entity must provide ERCOT documented proof of any PPA, TDSP interconnection agreement, or developer agreement that it relies on as a basis for any election under this paragraph. This election is valid through the earlier of December 31, 2029 or the date on which the election is revoked pursuant to paragraph (10) of this Section. On January 1, 2030, all SODGs and SOTGs will be subject to nodal pricing.

(8) For any SODG or SOTG for which the applicable Resource Entity has elected to opt out of nodal pricing, ERCOT shall settle the output of the SODG or SOTG using the Load Zone Settlement Point Price for the duration of the opt-out period so long as the SODG or SOTG is not physically modified for any purpose, including to increase the capacity of the unit or change the fuel type of the unit, except as necessary for routine maintenance or repairs to address normal wear and tear.

(9) If at any time ERCOT determines that the SODG or SOTG fails to meet the opt-out conditions in paragraph (8) above, ERCOT shall settle the output of the SODG or SOTG at the applicable nodal price as soon as practicable after providing written notice to the

affected Resource Entity.

(10) A Resource Entity that has opted out of nodal pricing for one or more SODGs or SOTGs pursuant to paragraph (7) of this Section may withdraw that election and begin receiving applicable nodal pricing for one or more such generators by submitting a properly completed election form (Section 23, Form N). An election of nodal pricing is irrevocable. ERCOT will effectuate the transition of an SODG or SOTG to nodal pricing in ERCOT Settlement systems as soon as practicable.

6.6.4 Real-Time Congestion Payment or Charge for Self-Schedules

(1) The congestion payment or charge to each QSE submitting a Self-Schedule calculated based on the difference in Real-Time Settlement Point Prices at the specified sink and the source of the Self-Schedule multiplied by the amount of the Self-Schedule. The congestion charge to each QSE for each of its Self-Schedule for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTCCAMT}_{\,q,\,s} = (\mathbf{RTSPP}_{\,sink,\,s} - \mathbf{RTSPP}_{\,source,\,s}) * (\mathbf{SSQ}_{\,q,\,s} * 1/4)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTCCAMT $_{q,\,s}$	\$	*Real-Time Congestion Cost Amount per QSE per Self-Schedule*—The congestion charge to QSE *q* for its Self-Schedule *s*, for the 15-minute Settlement Interval.
RTSPP $_{sink,\,s}$	\$/MWh	*Real-Time Settlement Point Price at the Sink of Self-Schedule*—The Real-Time Settlement Point Price at the sink of the Self-Schedule *s*, for the 15-minute Settlement Interval.
RTSPP $_{source,\,s}$	\$/MWh	*Real-Time Settlement Point Price at the Source of Self-Schedule*—The Real-Time Settlement Point Price at the source of the Self-Schedule *s*, for the 15-minute Settlement Interval.
SSQ $_{q,s}$	MW	*Self-Schedule Quantity per Self-Schedule*—The QSE *q*'s Self Schedule MW quantity for Self-Schedule *s*, for the 15-minute Settlement Interval.
q	none	A QSE.
s	none	A Self-Schedule.
sink	none	Sink Settlement Point
source	none	Source Settlement Point

(2) The total net congestion payments and charges to each QSE for all its Self-Schedules for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTCCAMTQSETOT}_{\,q} = \sum_{s} \mathbf{RTCCAMT}_{\,q,\,s}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTCCAMTQSETOT $_{q}$	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
RTCCAMT $_{q,\,s}$	$	*Real-Time Congestion Cost Amount per QSE per Self-Schedule*—The congestion payment or charge to QSE *q* for its Self-Schedule *s*, for the 15-minute Settlement Interval.
q	none	A QSE.
s	none	A Self-Schedule.

6.6.5 Base Point Deviation Charge

[NPRR1029: Replace the title for Section 6.6.5 above with the following upon system implementation:]

6.6.5 Set Point Deviation Charge

6.6.5.1 Resource Base Point Deviation Charge

(1) A QSE for a Generation Resource or Controllable Load Resource shall pay a Base Point Deviation Charge if the Resource did not follow Dispatch Instructions and Ancillary Service deployments within defined tolerances, except when the Dispatch Instructions and Ancillary Service deployments violate the Resource Parameters. The Base Point Deviation Charge does not apply to Generation Resources when Adjusted Aggregated Base Point (AABP) is less than the Resource's average telemetered LSL, the QSE's Generation Resources are operating in Constant Frequency Control (CFC) mode, or any time during the Settlement Interval when the telemetered Resource Status is set to ONTEST or STARTUP. The Base Point Deviation Charge does not apply to a Controllable Load Resource if the computed Base Point is equal to the snapshot of its telemetered power consumption for all SCED runs during the Settlement Interval or any time during the Settlement Interval when the telemetered Resource Status is set to OUTL. The desired output from a Generation Resource or desired consumption from a Controllable Load Resource during a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{AABP}_{\boldsymbol{q,\,r,\,p,\,i}} = \mathbf{AVGBP}_{\boldsymbol{q,\,r,\,p,\,i}} + \mathbf{AVGREG}_{\boldsymbol{q,\,r,\,p,\,i}}$$

Where:

$$\text{AVGBP}_{q,\,r,\,p,\,i} = \sum_{y} (\text{AVGBP5M}_{q,\,r,\,p,\,i,\,y}) / 3$$

$$\text{AVGREG}_{q,\,r,\,p,\,i} = \sum_{y} (\text{AVGREG5M}_{q,\,r,\,p,\,i,\,y}) / 3$$

$$\text{AVGREG5M}_{q,\,r,\,p,\,i,\,y} = (\text{AVGREGUP5M}_{q,\,r,\,p,\,i,\,y} - \text{AVGREGDN5M}_{q,\,r,\,p,\,i,\,y})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
AABP $_{q, r, p, i}$	MW	*Adjusted Aggregated Base Point per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments of Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AABP is calculated for the Combined Cycle Train considering all SCED Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train.
AVGBP $_{q, r, p, i}$	MW	*Average Base Point per QSE per Settlement Point per Resource*—The average of the five-minute clock interval Base Points over the 15-minute Settlement Interval *i* for Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*.
AVGBP5M $_{q, r, p, i, y}$	MW	*Average five-minute clock interval Base Point per QSE per Settlement Point per Resource*—The average Base Point for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the five-minute clock interval *y* within the 15-minute Settlement Interval *i*. The time-weighted average of the linearly ramped Base Points in a five-minute clock interval *y*. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five-minute clock interval *y*. The initial value of the linearly ramped Base Point will be the four second value of the previous linearly ramped Base Point at the time the new SCED Base Point is received into the ERCOT Energy Management System (EMS). The linear ramp is recalculated each time that a new Base Point is received from SCED. AVGBP5M is equal to the ABP value calculated for use in Generation Resource Energy Deployment Performance (GREDP) or the ABP value calculated for use in the Controllable Load Resource Energy Deployment Performance (CLREDP), as described in Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance.
AVGREG $_{q, r, p, i}$	MW	*Average Regulation Instruction per QSE per Settlement Point per Resource* —The average of the five-minute clock interval *y* Regulation Instruction Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* over the 15-minute Settlement Interval *i*.
AVGREG5M $_{q, r, p, i, y}$	MW	*Total Average five-minute clock interval Regulation Instruction per QSE per Settlement Point per Resource*—The total amount of regulation that the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* should have produced based on Load Frequency Control (LFC) deployment signals over the five-minute clock interval *y* within the 15-minute Settlement Interval *i*.
AVGREGUP5M $_{q, r, p, i, y}$	MW	*Average Regulation Instruction Up per QSE per Settlement Point per Resource*—The amount of Regulation Up (Reg-Up) that the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* should have produced based on LFC deployment signals over the five-minute clock interval *y* within the 15-minute Settlement Interval *i*.
AVGREGDN5M $_{q, r, p, i, y}$	MW	*Average Regulation Instruction Down per QSE per Settlement Point per Resource*—The amount of Regulation Down (Reg-Down) that the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* should have produced based on LFC deployment signals over the five-minute clock interval *y* within the 15-minute Settlement Interval *i*.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource or Controllable Load Resource.

Variable	Unit	Definition
i	None	A 15-minute Settlement Interval
y	none	A five-minute clock interval in the Settlement Interval.

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

6.6.5.1 Resource Set Point Deviation Charge

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

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

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

The above variables are defined as follows:

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

6.6.5.1.1 General Generation Resource and Controllable Load Resource Base Point

Deviation Charge

(1) Unless one of the exceptions specified in paragraphs (2) and (3) below applies, ERCOT shall charge a Base Point Deviation Charge for a Resource other than those described in Section 6.6.5.2, IRR Generation Resource Base Point Deviation Charge, and Section 6.6.5.3, Resources Exempt from Deviation Charges, when the telemetered generation of the Generation Resource or telemetered power consumption of the Controllable Load Resource over the 15-minute Settlement Interval is outside the tolerances defined later in this Section 6.6.5.1.1.

(2) ERCOT may not charge a QSE a Base Point Deviation Charge under paragraph (1) above when both of the following apply:

(a) The deviation of the Resource over the 15-minute Settlement Interval is in a direction that contributes to frequency corrections that resolve an ERCOT System frequency deviation; and

(b) The ERCOT System frequency deviation is greater than +/-0.05 Hz at any time during the 15-minute Settlement Interval.

(3) ERCOT may not charge a QSE a Base Point Deviation Charge under paragraph (1) above for any 15-minute Settlement Interval during which Responsive Reserve (RRS) is deployed.

[NPRR863: Replace paragraph (3) above with the following upon system implementation:]

(3) ERCOT may not charge a QSE a Base Point Deviation Charge under paragraph (1) above for any 15-minute Settlement Interval during which:

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

(b) Responsive Reserve (RRS) was manually deployed by ERCOT.

[NPRR963: Delete Section 6.6.5.1.1 above upon system implementation and renumber accordingly.]

6.6.5.1.1.1 Base Point Deviation Charge for Over Generation

(1) ERCOT shall charge a QSE for a Generation Resource for over-generation that exceeds the following tolerance. The tolerance is the greater of:

(a) 5% of the average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments; or

(b) Five MW for metered generation above the average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments.

(2) The over-generation charge to each QSE for each Generation Resource at each Resource Node Settlement Point is calculated as follows:

$$\mathbf{BPDAMT}_{q, r, p, i} = \mathbf{Max\ (PR1, RTSPP}_{p, i}\mathbf{)\ *\ OGEN}_{q, r, p, i}$$

Where:

$$\text{OGEN}_{q, r, p, i} = \text{Max}\ [0, (\text{TWTG}_{q, r, p, i} - ¼ * \text{Max}\ (((1 + \text{K1}) * \text{AABP}_{q, r, p, i}), (\text{AABP}_{q, r, p, i} + \text{Q1})))]$$

$$\text{TWTG}_{q, r, p, i} = (\sum_{y} (\text{AVGTG5M}_{q, r, p, i, y}) / 3) * ¼$$

The above variables are defined as follows:

Variable	Unit	Definition
BPDAMT $_{q, r, p, i}$	$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval *i*. The Base Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
TWTG $_{q, r, p, i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
AABP $_{q, r, p, i}$	MW	*Adjusted Aggregated Base Point per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments, of Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p,* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AABP is calculated for the Combined Cycle Train considering all SCED Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train.
AVGTG5M $_{q, r, p, i, y}$	MW	*Average Telemetered Generation for the 5 Minutes*—The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
OGEN $_{q, r, p, i}$	MWh	*Over Generation Volumes per QSE per Settlement Point per Resource*—The amount over-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15- minute Settlement Interval *i*.
PR1	$/MWh	The price to use for the Base Point Deviation Charge for over-generation when RTSPP is less than $20/MWh, $20/MWh.
K1	none	The percentage tolerance for over-generation, 5%.
Q1	MW	The MW tolerance for over-generation, five MW.

Variable	Unit	Definition
q	none	A QSE.
p	none	A Settlement Point.
r	none	A non-exempt, non-Intermittent Renewable Resource (IRR).
y	none	A five-minute clock interval in the Settlement Interval.
i	none	A 15-minute Settlement Interval.

[NPRR879, NPRR963, and NPRR1010: Replace applicable portions of Section 6.6.5.1.1.1 above with the following upon system implementation for NPRR879 or NPRR963; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; and renumber accordingly:]

6.6.5.2 Set Point Deviation Charge for Over Generation

(1) For Generation Resources that are not Energy Storage Resources (ESRs), ERCOT shall charge a QSE for a Generation Resource, including an Intermittent Renewable Resource (IRR) with an Ancillary Service award for at least one SCED interval within the 15-minute Settlement Interval, for over-generation that exceeds the following tolerance. The tolerance is the greater of:

(a) 5% of the AASP in the Settlement Interval; or

(b) Five MW above the AASP in the Settlement Interval.

(2) For instances in which an IRR has not received an Ancillary Service award or is not part of an IRR Group in which an IRR receives an Ancillary Service award for any SCED interval within the 15-minute Settlement Interval, Set Point Deviation Charges will be determined per Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge.

(3) The over-generation charge to each QSE for each Generation Resource, that is not part of an IRR Group or an ESR, at each Resource Node Settlement Point is calculated as follows:

$$\mathbf{SPDAMT}_{\boldsymbol{q, r, p, i}} = \mathbf{Max\ (PR1,\ RTSPP}_{\boldsymbol{p, i}}\mathbf{)\ *\ OGEN}_{\boldsymbol{q, r, p, i}}$$

Where:

$$\text{OGEN}_{q, r, p, i} = \text{Max}\ [0, (\text{TWTG}_{q, r, p, i} - ¼ * \text{Max}\ (((1 + \text{K1}) * \text{AASP}_{q, r, p, i}), (\text{AASP}_{q, r, p, i} + \text{Q1}))]$$

$$\text{TWTG}_{q, r, p, i} = (\sum_{y} (\text{AVGTG5M}_{q, r, p, i, y}) / 3) * ¼$$

(4) If any IRR in an IRR Group is awarded Ancillary Services for at least one SCED interval within the 15-minute Settlement Interval, then the deviation penalty is determined for the IRR Group and evenly allocated and charged to each IRR within that IRR Group as follows:

$$\mathbf{SPDAMT}_{q,\,r,\,p,\,i} = \mathbf{Max\ (PR1,\ RTSPP}_{p,\,i}\mathbf{)\ *\ OGEN}_{q,\,r,\,p,\,i}$$

Where:

$$\text{OGEN}_{q,\,r,\,p,\,i} = \text{Max}\ [0,\ (\text{TWTG}_{q,\,wg,\,p,\,i} - \tfrac{1}{4} * \text{Max}\ (((1 + \text{K1}) * \text{AASP}_{q,\,wg,\,p,\,i}),\ (\text{AASP}_{q,\,wg,\,p,\,i} + \text{Q1})))] / \text{N}$$

$$\text{TWTG}_{q,\,wg,\,p,\,i} = \sum_{r} (\sum_{y} (\text{AVGTG5M}_{q,\,r,\,p,\,i,\,y}) / 3) * \tfrac{1}{4}$$

$$\text{AASP}_{q,\,wg,\,p,\,i} = \sum_{r} (\text{AASP}_{q,\,r,\,p,\,i})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
SPDAMT $_{q,\,r,\,p,\,i}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*. The Set Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources.
RTSPP $_{p,\,i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
TWTG $_{q,\,r,\,p,\,i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
AASP $_{q,\,r,\,p,\,i}$	MW	*Average Aggregated Set Point per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Generation Resource *r* represented by QSE *q* at Settlement Point *p,* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AASP is calculated for the Combined Cycle Train considering all UDSPs to any Combined Cycle Generation Resources within the Combined Cycle Train.
AVGTG5M $_{q,\,r,\,p,\,i,\,y}$	MW	*Average Telemetered Generation for the 5 Minutes*—The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
OGEN $_{q,\,r,\,p,\,i}$	MWh	*Over Generation Volumes per QSE per Settlement Point per Resource*—The amount over-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval *i*.
PR1	$/MWh	The price to use for the Set Point Deviation Charge for over-generation when RTSPP is less than $20/MWh, $20/MWh.
K1	none	The percentage tolerance for over-generation, 5%.

Q1	MW	The MW tolerance for over-generation, five MW.
N	none	The number of IRRs within an IRR Group.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A non-exempt Resource.
y	none	A five-minute clock interval in the Settlement Interval.
i	none	A 15-minute Settlement Interval.
wg	none	An IRR Group.

6.6.5.1.1.2 Base Point Deviation Charge for Under Generation

(1) ERCOT shall charge a QSE for a Generation Resource for under generation if the metered generation is below the lesser of:

(a) 95% of the average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments; or

(b) The average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments minus five MW.

(2) The under-generation charge to each QSE for each Generation Resource at each Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{BPDAMT}_{q,r,p,i} = \mathbf{-1 * Min\ (PR2, RTSPP}_{p,i}\mathbf{) * Min\ (1, KP) * UGEN}_{q,r,p,i}$$

Where:

$$\text{UGEN}_{q,r,p,i} = \text{Max}\ [0, [\text{Min}\ ((1\text{- K2}) * ¼ * \text{AABP}_{q,r,p,i},$$

$$¼ * (\text{AABP}_{q,r,p,i} - \text{Q2})) - \text{TWTG}_{q,r,p,i}]]$$

$$\text{TWTG}_{q,r,p,i} = (\sum_{y} (\text{AVGTG5M}_{q,r,p,i,y}) / 3) * ¼$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{BPDAMT}_{q,r,p,i}$	\$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE q for Generation Resource r at Resource Node p, for its deviation from Base Point, for the 15-minute Settlement Interval i. A Base Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources.
$\text{RTSPP}_{p,i}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point p, for the 15-minute Settlement Interval i.

TWTG $_{q, r, p, i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
AABP $_{q, r, p, i}$	MW	*Adjusted Aggregated Base Point*—The aggregated Base Point adjusted for Ancillary Service deployments of Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AABP is calculated for the Combined Cycle Train considering all SCED Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train.
AVGTG5M $_{q, r, p, i, y}$	MW	*Average Telemetered Generation for the 5 Minutes* —The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
UGEN $_{q, r, p, i}$	MWh	*Under Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval *i*.
KP	none	The coefficient applied to the Settlement Point Price for under-generation charge, 1.0.
PR2	$/MWh	The price to use for the Base Point Deviation Charge for under-generation calculation when RTSPP is greater than -$20/MWh, -$20/MWh.
K2	none	The percentage tolerance for under-generation, 5%.
Q2	MW	The MW tolerance for under-generation, five MW.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A non-exempt, non-IRR.
y	none	A five-minute clock interval in the Settlement Interval.
i	none	A 15-minute Settlement Interval.

[NPRR879, NPRR963, and NPRR1010: Replace applicable portions of Section 6.6.5.1.1.2 above with the following upon system implementation for NPRR879 or NPRR963; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.5.2.1 Set Point Deviation Charge for Under Generation

(1) For Generation Resources that are not ESRs, ERCOT shall charge a QSE for a Generation Resource, including an IRR awarded Ancillary Service for at least one SCED interval within the 15-minute Settlement Interval, for under-generation if the telemetered generation is below the lesser of:

(a) 95% of the AASP in the Settlement Interval; or

(b) The AASP in the Settlement Interval minus five MW.

(2) For instances in which an IRR is not awarded Ancillary Service or is not part of an IRR Group in which an IRR is awarded Ancillary Service for any SCED interval within the 15-minute Settlement Interval, Set Point Deviation Charges will be determined per Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge.

(3) The under-generation charge to each QSE for each Generation Resource, that is not part of an IRR Group or an ESR, at each Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{SPDAMT}_{q,r,p,i} = \mathbf{-1 * Min\ (PR2, RTSPP}_{p,i}\mathbf{) * Min\ (1, KP) * UGEN}_{q,r,p,i}$$

Where:

$$UGEN_{q,r,p,i} = \text{Max}\ [0, [\text{Min}\ ((1- K2) * ¼ * AASP_{q,r,p,i},\ ¼ * (AASP_{q,r,p,i} - Q2)) - TWTG_{q,r,p,i}]]$$

$$TWTG_{q,r,p,i} = (\sum_{y} (AVGTG5M_{q,r,p,i,y}) / 3) * ¼$$

(4) If any IRR in an IRR Group is awarded Ancillary Service for at least one SCED interval within the 15-minute Settlement Interval, then the deviation penalty is determined for the IRR Group and evenly allocated and charged to each IRR within that IRR Group as follows:

$$\mathbf{SPDAMT}_{q,r,p,i} = \mathbf{-1 * Min\ (PR2, RTSPP}_{p,i}\mathbf{) * Min\ (1, KP) * UGEN}_{q,r,p,i}$$

Where:

$$UGEN_{q,r,p,i} = \text{Max}\ [0, [\text{Min}\ ((1 - K2) * ¼ * AASP_{q,wg,p,i},\ ¼ * (AASP_{q,wg,p,i} - Q2)) - TWTG_{q,wg,p,i}]] / N$$

$$TWTG_{q,wg,p,i} = \sum_{r} (\sum_{y} (AVGTG5M_{q,r,p,i,y}) / 3) * ¼$$

$$AASP_{q,wg,p,i} = \sum_{r} (AASP_{q,r,p,i})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
SPDAMT $_{q,r,p,i}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*. A Set Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources.
RTSPP $_{p,i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.

TWTG $_{q, r, p, i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
AASP $_{q, r, p, i}$	MW	*Average Aggregated Set Point*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Generation Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AASP is calculated for the Combined Cycle Train considering all UDSPs to any Combined Cycle Generation Resources within the Combined Cycle Train.
AVGTG5M $_{q, r, p, i, y}$	MW	*Average Telemetered Generation for the 5 Minutes* —The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
UGEN $_{q, r, p, i}$	MWh	*Under-Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval *i*.
KP	none	The coefficient applied to the Settlement Point Price for under-generation charge, 1.0.
PR2	$/MWh	The price to use for the Set Point Deviation Charge for under-generation calculation when RTSPP is greater than -$20/MWh, -$20/MWh.
K2	none	The percentage tolerance for under-generation, 5%.
Q2	MW	The MW tolerance for under-generation, five MW.
N	none	The number of IRRs within an IRR Group.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A non-exempt Resource.
y	none	A five-minute clock interval in the Settlement Interval.
i	none	A 15-minute Settlement Interval.
wg	none	An IRR Group.

6.6.5.1.1.3 Controllable Load Resource Base Point Deviation Charge for Over Consumption

(1) ERCOT shall charge a QSE for a Controllable Load Resource for over-consumption that exceeds the following tolerance. The tolerance is the greater of:

(a) XO% of the average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments; or

(b) YO MW for power consumption above the average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments.

(2) The Controllable Load Resource Base Point Deviation Charge for over-consumption variables XO and YO shall be subject to review and approval by the Technical Advisory Committee (TAC) and shall be posted to the ERCOT website no later than three Business Days after TAC approval.

(3) The charge to each QSE for non-excused over-consumption for each Controllable Load Resource during a 15-minute Settlement Interval in which the Controllable Load Resource has received a Base Point is calculated as follows:

$$\mathbf{BPDAMT}_{q, r, p, i} = \mathbf{-1 * Min\ (PRZ1, RTSPP}_{p, i}\mathbf{) * Min\ (1, KP1) * OCONSM}_{q, r, p, i}$$

Where:

$$\text{OCONSM}_{q, r, p, i} = \text{Max } [0, (\text{ATPC}_{q, r, p, i} - ¼* \text{Max } (((1 + \text{KLR1}) * \text{AABP}_{q, r, p, i}), (\text{AABP}_{q, r, p, i} + \text{QLR1}))]$$

$$\text{ATPC}_{q, r, p, i} = (\sum_{y} (\text{AVGTPC5M}_{q, r, p, i, y}) / 3) * ¼$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
BPDAMT $_{q, r, p, i}$	$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource or Controllable Load Resource *r* at Settlement Point *p*, for its deviation from Base Point, for the 15-minute Settlement Interval *i*.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
ATPC $_{q, r, p, i}$	MWh	*Average Telemetered Power Consumption per QSE per Settlement Point per Controllable Load Resource*—The average telemetered power consumption of the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i.*
AABP $_{q, r, p, i}$	MW	*Adjusted Aggregated Base Point per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments of Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
AVGTPC5M $_{q, r, p, i, y}$	MW	*Average Telemetered Power Consumption for the 5 Minutes*—The average telemetered power consumption of Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
OCONSM $_{q, r, p, i}$	MWh	*Over-Consumption Volumes per QSE per Settlement Point per Controllable Load Resource*—The amount over-consumed by the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*.
KP1	none	The coefficient applied to the Settlement Point Price for over-consumption charge, 1.0.
PRZ1	$/MWh	The price to use for the charge calculation when RTSPP is greater than -$20, -$20/MWh.
KLR1	none	The percentage tolerance for over-consumption of a Controllable Load Resource, XO%.

QLR1	MW	The MW tolerance for over-consumption of a Controllable Load Resource, YO MW.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Controllable Load Resource.
i	none	A 15-minute Settlement Interval.
y	none	A five-minute clock interval in the Settlement Interval.

[NPRR963, NPRR1010, and NPRR1014: Replace applicable portions of Section 6.6.5.1.1.3 above with the following upon system implementation for NPRR963 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; and renumber accordingly:]

6.6.5.3 Controllable Load Resource Set Point Deviation Charge for Over Consumption

(1) ERCOT shall charge a QSE of a Controllable Load Resource, for over-consumption that exceeds the following tolerance. The tolerance is the greater of:

(a) XO% of the AASP in the Settlement Interval; or

(b) YO MW above the AASP in the Settlement Interval.

(2) The Controllable Load Resource Set Point Deviation Charge for over-consumption variables XO and YO shall be subject to review and approval by the Technical Advisory Committee (TAC) and shall be posted to the ERCOT website no later than three Business Days after TAC approval.

(3) The charge to each QSE for non-excused over-consumption for each Controllable Load Resource, during a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{SPDAMT}_{q,r,p,i} = -1 * \mathbf{Min}\ (\mathbf{PRZ1}, \mathbf{RTSPP}_{p,i}) * \mathbf{Min}\ (1, \mathbf{KP1}) * \mathbf{OCONSM}_{q,r,p,i}$$

Where:

$$\text{OCONSM}_{q,r,p,i} = \text{Max}\ [0, (\text{ATPC}_{q,r,p,i} - ¼ * \text{Max}\ (((1 + \text{KLR1}) * \text{AASP}_{q,r,p,i}), (\text{AASP}_{q,r,p,i} + \text{QLR1})))]$$

$$\text{ATPC}_{q,r,p,i} = (\sum_{y} (\text{AVGTPC5M}_{q,r,p,i,y}) / 3) * ¼$$

The above variables are defined as follows:

Variable	Unit	Definition
SPDAMT $_{q,r,p,i}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Controllable Load Resource *r* at Settlement Point *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*.

RTSPP $_{p,\ i}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
ATPC $_{q,\ r,\ p,\ i}$	MWh	*Average Telemetered Power Consumption per QSE per Settlement Point per Controllable Load Resource*—The average telemetered power consumption of the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
AASP $_{q,\ r,\ p,\ i}$	MW	*Average Aggregated Set Point for the Resource per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
AVGTPC5M $_{q,\ r,\ p,\ i,\ y}$	MW	*Average Telemetered Power Consumption for the 5 Minutes*—The average telemetered power consumption of Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
OCONSM $_{q,\ r,\ p,\ i}$	MWh	*Over-Consumption Volumes per QSE per Settlement Point per Controllable Load Resource*—The amount over-consumed by the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*.
KP1	none	The coefficient applied to the Settlement Point Price for over-consumption charge, 1.0.
PRZ1	\$/MWh	The price to use for the charge calculation when RTSPP is greater than -\$20, -\$20/MWh.
KLR1	none	The percentage tolerance for over-consumption of a Controllable Load Resource, XO%.
QLR1	MW	The MW tolerance for over-consumption of a Controllable Load Resource, YO MW.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Controllable Load Resource.
i	none	A 15-minute Settlement Interval.
y	none	A five-minute clock interval in the Settlement Interval.

6.6.5.1.1.4 Controllable Load Resource Base Point Deviation Charge for Under Consumption

(1) ERCOT shall charge a QSE for a Controllable Load Resource for under-consumption if the average telemetered power consumption is below than the lesser of:

(a) [100-XU]% of the average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments; or

(b) The average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments minus YU MW.

(2) The Controllable Load Resource Base Point Deviation Charge for under-consumption variables XU and YU shall be subject to review and approval by TAC and shall be posted to the ERCOT website no later than three Business Days after TAC approval.

(3) The charge to each QSE for non-excused under-consumption of each Controllable Load Resource during a 15-minute Settlement Interval in which the Controllable Load Resource has received a Base Point is calculated as follows:

$$\mathbf{BPDAMT}_{q, r, p, i} = \mathbf{Max\ (PRZ2,\ RTSPP}_{p, i}\mathbf{)\ *\ UCONSM}_{q, r, p, i}$$

Where:

$$\text{UCONSM}_{q, r, p, i} = \text{Max } [0, [\text{Min } ((1 - \text{KLR2}) * ¼ * \text{AABP}_{q, r, p, i}, ¼ * (\text{AABP}_{q, r, p, i} - \text{QLR2})) - \text{ATPC}_{q, r, p, i}]]$$

$$\text{ATPC}_{q, r, p, i} = (\sum_{y} (\text{AVGTPC5M}_{q, r, p, i, y}) / 3) * ¼$$

The above variables are defined as follows:

Variable	Unit	Definition
BPDAMT $_{q, r, p, i}$	$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource or Controllable Load Resource *r* at Settlement Point *p*, for its deviation from Base Point, for the 15-minute Settlement Interval *i*.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
ATPC $_{q, r, p, i}$	MWh	*Average Telemetered Power Consumption per QSE per Settlement Point per Controllable Load Resource*—The average telemetered power consumption of the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
AABP $_{q, r, p, i}$	MW	*Adjusted Aggregated Base Point per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments of Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
AVGTPC5M $_{q, r, p, i, y}$	MW	*Average Telemetered Power Consumption for the 5 Minutes*—The average telemetered power consumption of Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
UCONSM $_{q, r, p, i}$	MWh	*Under Consumption Volumes per QSE per Settlement Point per Controllable Load Resource*—The amount under-consumed by the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*.
PRZ2	$/MWh	The price to use for the Base Point Deviation Charge for under-consumption calculation when RTSPP is less than $20/MWh, $20/MWh.
KLR2		The percentage tolerance for under-consumption of a Controllable Load Resource, XU%.
QLR2	MW	The MW tolerance for under-consumption of a Controllable Load Resource, YU MW.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Controllable Load Resource.
i	none	A 15-minute Settlement Interval.
y	none	A five-minute clock interval in the Settlement Interval.

[NPRR963, NPRR1010, and NPRR1014: Replace applicable portions of Section 6.6.5.1.1.4 above with the following upon system implementation for NPRR963 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.5.3.1 Controllable Load Resource Set Point Deviation Charge for Under Consumption

(1) ERCOT shall charge a QSE for a Controllable Load Resource, for under-consumption if the average telemetered power consumption is below than the lesser of:

(a) [100-XU]% of the AASP in the Settlement Interval; or

(b) The AASP in the Settlement Interval minus YU MW.

(2) The Controllable Load Resource Set Point Deviation Charge for under-consumption variables XU and YU shall be subject to review and approval by TAC and shall be posted to the ERCOT website no later than three Business Days after TAC approval.

(3) The charge to each QSE for non-excused under-consumption of each Controllable Load Resource, during a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{SPDAMT}_{q,\,r,\,p,\,i} = \mathbf{Max\ (PRZ2,\ RTSPP}_{p,\,i}\mathbf{)\ *\ UCONSM}_{q,\,r,\,p,\,i}$$

Where:

$$\text{UCONSM}_{q,\,r,\,p,\,i} = \text{Max }[0, [\text{Min }((1 - \text{KLR2}) * \tfrac{1}{4} * \text{AASP}_{q,\,r,\,p,\,i}, \tfrac{1}{4} * (\text{AASP}_{q,\,r,\,p,\,i} - \text{QLR2})) - \text{ATPC}_{q,\,r,\,p,\,i}]]$$

$$\text{ATPC}_{q,\,r,\,p,\,i} = (\sum_{y} (\text{AVGTPC5M}_{q,\,r,\,p,\,i,\,y}) / 3) * \tfrac{1}{4}$$

The above variables are defined as follows:

Variable	Unit	Definition
SPDAMT $_{q,\,r,\,p,\,i}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Controllable Load Resource *r* at Settlement Point *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*.
RTSPP $_{p,\,i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
ATPC $_{q,\,r,\,p,\,i}$	MWh	*Average Telemetered Power Consumption per QSE per Settlement Point per Controllable Load Resource*—The average telemetered power consumption of the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
AASP $_{q,\,r,\,p,\,i}$	MW	*Average Aggregated Set Point for the Resource per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.

$\text{AVGTPC5M}_{q,\ r,\ p,\ i,\ y}$	MW	*Average Telemetered Power Consumption for the 5 Minutes*—The average telemetered power consumption of Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
$\text{UCONSM}_{q,\ r,\ p,\ i}$	MWh	*Under-Consumption Volumes per QSE per Settlement Point per Controllable Load Resource*—The amount under-consumed by the Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*.
PRZ2	$/MWh	The price to use for the Set Point Deviation Charge for under-consumption calculation when RTSPP is less than $20/MWh, $20/MWh.
KLR2		The percentage tolerance for under-consumption of a Controllable Load Resource, XU%.
QLR2	MW	The MW tolerance for under-consumption of a Controllable Load Resource, YU MW.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Controllable Load Resource.
i	none	A 15-minute Settlement Interval.
y	none	A five-minute clock interval in the Settlement Interval.

6.6.5.2 IRR Generation Resource Base Point Deviation Charge

(1) ERCOT shall charge a QSE for an IRR a Base Point Deviation Charge if the IRR metered generation is more than 10% above its Adjusted Aggregated Base Point and the flag signifying that the IRR has received a Base Point below the HDL used by SCED has been received.

(2) The charge to each QSE for non-excused over-generation of each IRR that is not included in an IRR Group at each Resource Node Settlement Point during a 15-minute Settlement Interval, is calculated as follows:

If the flag signifying that the IRR has received a Base Point below the HDL used by SCED is not set in all SCED intervals within the 15-minute Settlement Interval:

$$\mathbf{BPDAMT}_{q,\ r,\ p,\ i} = \mathbf{0}$$

Otherwise, if the flag signifying that the IRR has received a Base Point below the HDL used by SCED is set in all SCED intervals within the 15-minute Settlement Interval:

$$\mathbf{BPDAMT}_{q,\ r,\ p,\ i} = \mathbf{Max\ (PR1,\ RTSPP}_{p,\ i}\mathbf{)\ *\ OGENIRR}_{q,\ r,\ p,\ i}$$

Where:

$$\text{OGENIRR}_{q,\ r,\ p,\ i} = \text{Max}\ [0,\ \text{TWTG}_{q,\ r,\ p,\ i} - ¼ * \text{AABP}_{q,\ r,\ p,\ i} * (1 + \text{KIRR})]$$

$$\text{TWTG}_{q,\ r,\ p,\ i} = (\sum_{y} (\text{AVGTG5M}_{q,\ r,\ p,\ i,\ y}) / 3) * ¼$$

(3) The charge to each QSE for non-excused over-generation of each IRR that is included in an IRR Group, at each Resource Node Settlement Point, if the Real-Time metered generation is greater than the upper tolerance during a 15-minute Settlement Interval, is calculated as follows:

If the flag signifying that the IRR has received a Base Point below the HDL used by SCED is not set in all SCED intervals within the 15-minute Settlement Interval for any of the IRRs within an IRR Group, then for all IRRs within an IRR Group:

$$\mathbf{BPDAMT}_{q, r, p} = \mathbf{0}$$

If the flag signifying that the IRR has received a Base Point below the HDL used by SCED is set in all SCED intervals within the 15-minute Settlement Interval for any of the IRRs within an IRR Group, then the deviation penalty is determined for the IRR Group and evenly allocated and charged to each IRR within that IRR Group:

$$\mathbf{BPDAMT}_{q, r, p} = \mathbf{[Max\ (PR1, RTSPP}_{p}\mathbf{)\ *\ OGENIRR}_{q, wg, i}\mathbf{]\ /\ N}$$

Where:

$$\text{OGENIRR}_{q, wg, i} = \text{Max}\ [0, \text{TWTG}_{q, wg, i} - ¼ * \text{AABP}_{q, wg, i} * (1 + \text{KIRR})]$$

$$\text{TWTG}_{q, wg, i} = \sum_{r} (\text{TWTG}_{q, r, p, i})$$

$$\text{AABP}_{q, wg, i} = \sum_{r} (\text{AABP}_{q, r, p, i})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{BPDAMT}_{q, r, p, i}$	\$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval *i*.
$\text{RTSPP}_{p, i}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Resource Node *p*, for the 15-minute Settlement Interval *i*.
$\text{TWTG}_{q, r, p, i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*.
$\text{AABP}_{q, r, p, i}$	MW	*Adjusted Aggregated Base Point Generation per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments, of Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
$\text{AVGTG5M}_{q, r, p, i, y}$	MW	*Average Telemetered Generation for the 5 Minutes*—The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
$\text{OGENIRR}_{q, r, p, i}$	MWh	*Over Generation Volumes per QSE per Settlement Point per IRR Generation Resource*—The amount over generated by the IRR *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval *i*.
PR1	\$/MWh	The price to use for the charge calculation when RTSPP is less than \$20/MWh, \$20/MWh.
KIRR	none	The percentage tolerance for over-generation of an IRR, 10%.
N	none	The number of IRRs within an IRR Group.

q	none	A QSE.
p	none	A Settlement Point.
r	none	An IRR Generation Resource or an IRR within an IRR Group.
i	none	A 15-minute Settlement Interval.
y	none	A five-minute clock interval in the Settlement Interval.
wg	none	An IRR Group.

[NPRR879, NPRR963, NPRR1010, and NPRR1111: Replace applicable portions of Section 6.6.5.2 above with the following upon system implementation for NPRR879 or NPRR963; upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation of SCR819 for NPRR1111; and renumber accordingly:]

6.6.5.4 IRR Generation Resource Set Point Deviation Charge

(1) ERCOT shall charge a QSE for an IRR a Set Point Deviation Charge if the IRR telemetered generation is more than 5% above its AASP, the flag signifying that the IRR has received a Base Point below the HDL used by SCED has been received or the IRR has been instructed not to exceed its Base Point, and the IRR is not awarded Ancillary Service and is not part of an IRR Group in which at least one IRR is awarded Ancillary Service for at least one SCED interval within the 15-minute Settlement Interval.

(2) For instances in which an IRR is awarded Ancillary Service or is part of an IRR Group in which at least one IRR is awarded Ancillary Service for at least one SCED interval within the 15-minute Settlement Interval, Set Point Deviation Charges will be determined per Section 6.6.5.2, Set Point Deviation Charge for Over Generation, and Section 6.6.5.2.1, Set Point Deviation Charge for Under Generation.

(3) The charge to each QSE for non-excused over-generation of each IRR that is not included in an IRR Group at each Resource Node Settlement Point during a 15-minute Settlement Interval, is calculated as follows:

If the flag signifying that the IRR has received a Base Point below the HDL used by SCED or the IRR has been instructed not to exceed its Base Point is not set in all SCED intervals within the 15-minute Settlement Interval:

$$\textbf{SPDAMT}_{q,\,r,\,p,\,i} = \quad \mathbf{0}$$

Otherwise, if the flag signifying that the IRR has received a Base Point below the HDL used by SCED or the IRR has been instructed not to exceed its Base Point is set in all SCED intervals within the 15-minute Settlement Interval:

$$\textbf{SPDAMT}_{q,\,r,\,p,\,i} = \quad \textbf{Max (PR1, RTSPP}_{p,\,i}\textbf{) * OGENIRR}_{q,\,r,\,p,\,i}$$

Where:

$$\text{OGENIRR}_{q,\,r,\,p,\,i} = \text{Max}\,[0, \text{TWTG}_{q,\,r,\,p,\,i} - \tfrac{1}{4} * \text{AASP}_{q,\,r,\,p,\,i} * (1 + \text{KIRR})]$$

$$\text{TWTG}_{q,\,r,\,p,\,i} = (\sum_{y} (\text{AVGTG5M}_{q,\,r,\,p,\,i,\,y}) / 3) * \tfrac{1}{4}$$

(4) The charge to each QSE for non-excused over-generation of each IRR that is included in an IRR Group, at each Resource Node Settlement Point, if the telemetered generation is greater than the upper tolerance during a 15-minute Settlement Interval, is calculated as follows:

If the flag signifying that the IRR has received a Base Point below the HDL used by SCED or the IRR has been instructed not to exceed its Base Point is not set in all SCED intervals within the 15-minute Settlement Interval for any of the IRRs within an IRR Group, then for all IRRs within an IRR Group:

$$\mathbf{SPDAMT}_{q,\,r,\,p} = \mathbf{0}$$

If the flag signifying that the IRR has received a Base Point below the HDL used by SCED or the IRR has been instructed not to exceed its Base Point is set in all SCED intervals within the 15-minute Settlement Interval for any of the IRRs within an IRR Group, then the deviation penalty is determined for the IRR Group and evenly allocated and charged to each IRR within that IRR Group:

$$\mathbf{SPDAMT}_{q,\,r,\,p} = \mathbf{Max\,(PR1, RTSPP}_{p}\mathbf{)} * \mathbf{OGENIRR}_{q,\,r,\,i}$$

Where:

$$\text{OGENIRR}_{q,\,r,\,i} = \text{Max}\,[0, \text{TWTG}_{q,\,wg,\,i} - \tfrac{1}{4} * \text{AASP}_{q,\,wg,\,i} * (1 + \text{KIRR})] / \text{N}$$

$$\text{TWTG}_{q,\,wg,\,i} = \sum_{r} (\text{TWTG}_{q,\,r,\,p,\,i})$$

$$\text{AASP}_{q,\,wg,\,i} = \sum_{r} (\text{AASP}_{q,\,r,\,p,\,i})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
SPDAMT $_{q,\,r,\,p,\,i}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*.
RTSPP $_{p,\,i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Resource Node *p*, for the 15-minute Settlement Interval *i*.
TWTG $_{q,\,r,\,p,\,i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*.
AASP $_{q,\,r,\,p,\,i}$	MW	*Average Aggregated Set Point Generation per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Generation Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
AVGTG5M $_{q,\,r,\,p,\,i,\,y}$	MW	*Average Telemetered Generation for the 5 Minutes*—The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.

$OGENIRR_{q, r, p, i}$	MWh	*Over Generation Volumes per QSE per Settlement Point per IRR Generation Resource*—The amount over generated by the IRR *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval *i*.
PR1	$/MWh	The price to use for the charge calculation when RTSPP is less than $20/MWh, $20/MWh.
KIRR	none	The percentage tolerance for over-generation of an IRR, 5%.
N	none	The number of IRRs within an IRR Group.
q	none	A QSE.
p	none	A Settlement Point.
r	none	An IRR Generation Resource not awarded Ancillary Service or an IRR within an IRR Group where no member of the IRR Group was awarded Ancillary Service.
i	none	A 15-minute Settlement Interval.
y	none	A five-minute clock interval in the Settlement Interval.
wg	none	An IRR Group.

[NPRR963, NPRR1010, NPRR1014, NPRR1029, and NPRR1111: Insert applicable portions of Section 6.6.5.5 below upon system implementation for NPRR963, NPRR1014, and NPRR1029; upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation of SCR819 for NPRR1111; and renumber accordingly:]

6.6.5.5 Energy Storage Resource Set Point Deviation Charge for Over Performance

(1) ERCOT shall charge a QSE for an ESR a Set Point Deviation Charge for over-performance if the telemetered generation or consumption exceeds the specified tolerance.

(2) The tolerance is the greater of 3% of the AASP for the ESR in the Settlement Interval, or three MW above the AASP for the ESR in the Settlement Interval if the Resource meets the following conditions:

(a) The ESR is not a DC-Coupled Resource; or

(b) The ESR is a DC-Coupled Resource and meets the conditions to be treated in the same manner as an ESR as specified in paragraph (1) of Section 3.8.7, DC-Coupled Resources, anytime during the Settlement Interval.

(3) The tolerance will be 5% of the AASP for a DC-Coupled Resource in the Settlement Interval if the ESR meets the conditions to be treated in the same manner as an IRR as specified in paragraph (2) of Section 3.8.7.

(4) The deviation charge for over-performance for each QSE for each ESR at each Resource Node Settlement Point will be calculated as follows:

If the ESR meets the conditions of paragraph (3) above and a flag signifying that the DC-Coupled Resource has received a Base Point below the HDL used by SCED or it has been instructed not to exceed its Base Point is not set in all SCED intervals within the 15-minute Settlement Interval, then:

$$\mathbf{SPDAMT}_{q,\,r,\,p,\,i} = \mathbf{0}$$

Otherwise:

$$\mathbf{SPDAMT}_{q,\,r,\,p,\,i} = \mathbf{Max\ (PR3,\ RTSPP}_{p,\,i}\mathbf{)\ *\ OPESR}_{q,\,r,\,p,\,i}$$

Where:

If the ESR meets the conditions of paragraph (2) above, then:

$$\text{OPESR}_{q,\,r,\,p,\,i} = \text{Max}\ [0,\ (\text{TWTG}_{q,\,r,\,p,\,i} - ¼ * \text{Max}\ [(\text{AASP}_{q,\,r,\,p,\,i} + \text{ABS}\ (\text{K3}* \text{AASP}_{q,\,r,\,p,\,i})),\ (\text{AASP}_{q,\,r,\,p,\,i} + \text{Q3})])]$$

If the ESR meets the conditions of paragraph (3) above, then:

$$\text{OPESR}_{q,\,r,\,p,\,i} = \text{Max}\ [0,\ (\text{TWTG}_{q,\,r,\,p,\,i} - ¼ * (\text{AASP}_{q,\,r,\,p,\,i} + \text{ABS}\ (\text{K5}* \text{AASP}_{q,\,r,\,p,\,i})))]$$

Where:

$$\text{TWTG}_{q,\,r,\,p,\,i} = (\sum_{y} (\text{AVGTG5M}_{q,\,r,\,p,\,i,\,y}) / 3) * ¼$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{SPDAMT}_{q,\,r,\,p,\,i}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Resource *r* at Resource Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*.
$\text{RTSPP}_{p,\,i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
$\text{TWTG}_{q,\,r,\,p,\,i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation or consumption of Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*.
$\text{AASP}_{q,\,r,\,p,\,i}$	MW	*Average Aggregated Set Point per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Resource *r* represented by QSE *q* at Settlement Point *p,* for the 15-minute Settlement Interval *i*.
$\text{AVGTG5M}_{q,\,r,\,p,\,i,\,y}$	MW	*Average Telemetered Generation for the 5 Minutes*—The average telemetered generation or consumption of Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
$\text{OPESR}_{q,\,r,\,p,\,i}$	MWh	*Over-Performance Volumes per QSE per Settlement Point per Resource*—The amount the ESR *r* over-performed, represented by QSE *q* at Resource Node *p,* for the 15-minute Settlement Interval *i*.
PR3	$/MWh	The price to use for the Set Point Deviation Charge for over-performance when RTSPP is less than $20/MWh, $20/MWh.
K3	none	The percentage tolerance for over-performance per paragraph (2) above, 3%.
K5	none	The percentage tolerance for over-performance per paragraph (3) above, 5%.
Q3	MW	The MW tolerance for over-performance, three MW.

q	none	A QSE.
p	none	A Settlement Point.
r	none	An ESR.
y	none	A five-minute clock interval in the Settlement Interval.
i	none	A 15-minute Settlement Interval.

[NPRR963, NPRR1010, NPRR1014, and NPRR1029: Insert applicable portions of Section 6.6.5.5.1 below upon system implementation for NPRR963, NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.5.5.1 Energy Storage Resource Set Point Deviation Charge for Under Performance

(1) ERCOT shall charge a QSE for an ESR a Set Point Deviation Charge for under-performance if the telemetered generation or consumption is below the specified tolerance.

(2) The tolerance is the lesser of 3% of the AASP for the ESR in the Settlement Interval, or three MW below the AASP for the ESR in the Settlement Interval, if the Resource meets the following conditions:

(a) The ESR is not a DC-Coupled Resource; or

(b) The ESR is a DC-Coupled Resource and meets the conditions to be treated in the same manner as an ESR as specified in paragraph (1) of Section 3.8.7, DC-Coupled Resources, anytime during the Settlement Interval.

(3) The deviation charge for under-performance for each QSE for each ESR at each Resource Node Settlement Point will be calculated as follows:

$$\mathbf{SPDAMT}_{q, r, p, i} = \mathbf{(-1) * Min\ (PR4, RTSPP}_{p, i}\mathbf{) * Min\ (1, KP2) * UPESR}_{q, r, p, i}$$

Where:

If the ESR meets the conditions of paragraph (2) above, then:

$$\text{UPESR}_{q, r, p, i} = \text{Max } [0, ¼ * \text{Min } [(\text{AASP}_{q, r, p, i} - \text{ABS } (\text{K4} * \text{AASP}_{q, r, p, i})), (\text{AASP}_{q, r, p, i} - \text{Q4})] - \text{TWTG}_{q, r, p, i}]$$

Else:

$$\text{UPESR}_{q, r, p, i} = 0$$

Where:

$$\text{TWTG}_{q, r, p, i} = (\sum_{y} (\text{AVGTG5M}_{q, r, p, i, y}) / 3) * ¼$$

The above variables are defined as follows:

Variable	Unit	Definition
SPDAMT $_{q, r, p, i}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Resource *r* at Resource Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
TWTG $_{q, r, p, i}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation or consumption of Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*.
AASP $_{q, r, p, i}$	MW	*Average Aggregated Set Point per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Resource *r* represented by QSE *q* at Settlement Point *p,* for the 15-minute Settlement Interval *i*.
AVGTG5M $_{q, r, p, i, y}$	MW	*Average Telemetered Generation for the 5 Minutes*—The average telemetered generation or consumption of Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*.
UPESR $_{q, r, p, i}$	MWh	*Under-Performance Volumes per QSE per Settlement Point per Resource*—The amount the ESR *r* under-performed represented by QSE *q* at Resource Node *p,* for the 15-minute Settlement Interval *i*.
PR4	$/MWh	The price to use for the Set Point Deviation Charge for under-performance when RTSPP is greater than -$20/MWh, -$20/MWh.
K4	none	The percentage tolerance for under-performance, 3%.
Q4	MW	The MW tolerance for under-performance, three MW.
KP2	none	The coefficient applied to the Settlement Point Price for under-performance charge, 1.0.
q	none	A QSE.
p	none	A Settlement Point.
r	none	An ESR.
y	none	A five-minute clock interval in the Settlement Interval.
i	none	A 15-minute Settlement Interval.

6.6.5.3 Resources Exempt from Deviation Charges

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

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

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

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

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

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

[NPRR863, NPRR963, NPRR1000, NPRR1010, NPRR1014, NPRR1046, NPRR1058, and NPRR1111: Replace applicable portions of Section 6.6.5.3 above with the following upon system implementation for NPRR863, NPRR963, NPRR1014, or NPRR1058; upon system implementation of NPRR1000 for NPRR1000 and NPRR1046; upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation of SCR819 for NPRR1111; and renumber accordingly:]

6.6.5.6 Resources Exempt from Deviation Charges

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6.6.5.4 Base Point Deviation Payment

(1) ERCOT shall pay the Base Point Deviation Charges collected from the QSEs representing Resources to the QSEs representing Load based on LRS. The payment to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LABPDAMT}_{q} = \mathbf{(-1) * BPDAMTTOT * LRS}_{q}$$

Where:

$$\text{BPDAMTTOT} = \sum_{q} \text{BPDAMTQSETOT}_{q}$$

$$\text{BPDAMTQSETOT}_{q} = \sum_{p}\sum_{r} \text{BPDAMT}_{q, r, p}$$

The above variables are defined as follows:

Variable	Unit	Definition
LABPDAMT_{q}	$	*Load-Allocated Base Point Deviation Amount per QSE*—QSE *q*'s share of the total charge for all Resources' Base Point deviations, based on LRS for the 15-minute Settlement Interval.
BPDAMTTOT	$	*Base Point Deviation Amount Total*—The total of Base Point Deviation Charges to all QSEs for all Resources, for the 15-minute Settlement Interval.
BPDAMTQSETOT_{q}	$	*Base Point Deviation Amount QSE Total per QSE*—The total of Base Point Deviation Charges to QSE *q* for all Resources represented by this QSE, for the 15-minute Settlement Interval.
$\text{BPDAMT}_{q, r, p}$	$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource or Controllable Load Resource *r* at Settlement Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval. A Base Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources.
LRS_{q}	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource or Controllable Load Resource.

[NPRR1010: Replace Section 6.6.5.4 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.6.5.4 Set Point Deviation Payment

(1) ERCOT shall pay the Set Point Deviation Charges collected from the QSEs representing Resources to the QSEs representing Load based on LRS. The payment to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LASPDAMT}_{q} = (-1) * \mathbf{SPDAMTTOT} * \mathbf{LRS}_{q}$$

Where:

$$\text{SPDAMTTOT} = \sum_{q} \text{SPDAMTQSETOT}_{q}$$

$$\text{SPDAMTQSETOT}_{q} = \sum_{p}\sum_{r} \text{SPDAMT}_{q, r, p}$$

The above variables are defined as follows:

Variable	Unit	Definition
LASPDAMT $_q$	$	*Load-Allocated Set Point Deviation Amount per QSE*—QSE *q*'s share of the total charge for all Resources' Set Point deviations, based on LRS for the 15-minute Settlement Interval.
SPDAMTTOT	$	*Set Point Deviation Amount Total*—The total of Set Point Deviation Charges to all QSEs for all Resources, for the 15-minute Settlement Interval.
SPDAMTQSETOT $_q$	$	*Set Point Deviation Amount QSE Total per QSE*—The total of Set Point Deviation Charges to QSE *q* for all Resources represented by this QSE, for the 15-minute Settlement Interval.
SPDAMT $_{q, r, p}$	$	*Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource or Controllable Load Resource *r* at Settlement Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval. A Set Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources.
LRS $_q$	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource or Controllable Load Resource.

6.6.6 Reliability Must-Run Settlement

[NPRR885: Replace Section 6.6.6 above with the following upon system implementation:]

6.6.6 Reliability Must-Run and Must-Run Alternative Settlement

6.6.6.1 RMR Standby Payment

(1) The Standby Payment for RMR Service is paid to each QSE representing an RMR Unit for each RMR Unit for each contracted hour under performance requirements set forth in Section 22, Attachment B, Standard Form Reliability Must-Run Agreement, and other performance requirements in these Protocols. For Initial Settlement, the Standby Payment is either the "Initial Standby Cost" stated in the RMR Agreement or the revised Standby Cost calculated in accordance with paragraph (2) of Section 3.14.1.13, Updated Budgets During the Term of an RMR Agreement. For Final and True-Up Settlements, the Standby Payment is based on the RMR Unit's actual Eligible Cost, if available.

(2) The Standby Payment to each QSE for each RMR Unit for each hour is calculated as follows:

$$\textbf{RMRSBAMT}_{q,\,r} \quad = \quad \textbf{(-1) * RMRSBPR}_{q,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RMRSBAMT_{q,r}$	$	*Reliability Must Run Standby Payment per QSE per Resource by hour*—The Standby Payment to QSE *q* for RMR Unit *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RMRSBPR_{q,r}$	$ per hour	*Reliability Must Run Standby Price per QSE per Resource by hour*—The hourly standby cost for RMR Unit *r* represented by QSE *q*, for the hour. See item (3) below. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An RMR Unit.

(3) For the Initial Settlement and resettlements executed before true-up and before actual cost data is submitted, the standby price of an RMR Unit is either the "Initial Standby Cost" stated in the RMR Agreement or the revised Standby Cost calculated in accordance with paragraph (2) of Section 3.14.1.13. For other resettlements, the standby price of an RMR Unit for each hour is calculated as follows:

$$\mathbf{RMRSBPR_{q,r} = (RMRMNFNCC_{q,r} * (1 + RMRIF * RMRCRF_{q,r} * RMRARF_{q,r}) + RMRMNFCC_{q,r}) / MH_{q,r}}$$

Where:

RMR Capacity Reduction Factor

If $(RMRTCAPA_{q,r} + RMRTCAP_{q,r} \geq RMRCCAP_{q,r})$, then $RMRCRF_{q,r} = 1$

Otherwise

$$RMRCRF_{q,r} = \text{Max}\,(0, 1 - 2 * (RMRCCAP_{q,r} - RMRTCAP_{q,r}) / RMRCCAP_{q,r})$$

RMR Availability Reduction Factor

If $(RMRHREAF_{q,r} \geq RMRTA_{q,r})$, then $RMRARF_{q,r} = 1$

Otherwise

$$RMRARF_{q,r} = \text{Max}\,(0, 1 - (RMRTA_{q,r} - RMRHREAF_{q,r}) * 2)$$

RMR Hourly Rolling Equivalent Availability Factor

$$RMRHREAF_{q,r} = \text{Min}\,(1, \sum_{hr=h-4379}^{h} (RMRAFLAG_{q,r,hr} * HSL_{q,r,hr}) \;/\; \sum_{hr=h-4379}^{h} RMRCCAP_{q,r})$$

Availability for a Combined Cycle Train will be determined pursuant to contractual terms but no more than once per hour.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
RMRSBPR $_{q,\ r}$	\$ per hour	*Reliability Must-Run Standby Price per QSE per Resource by hour*—The hourly standby cost for RMR Unit *r* represented by QSE *q,* for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRARF $_{q,\ r}$	none	*Reliability Must-Run Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor of RMR Unit *r* represented by QSE *q*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRCRF $_{q,\ r}$	none	*Reliability Must-Run Capacity Reduction Factor per QSE per Resource by hour*—The capacity reduction factor of the RMR Unit *r* represented by QSE *q*, for the hour. See paragraph (2) of Section 3.14.1.17, Incentive Factor. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRCCAP $_{q,\ r}$	MW	*Reliability Must-Run Contractual Capacity per QSE per Resource*—The seasonal capacity of RMR Unit *r* represented by QSE *q* as specified in the RMR Agreement. The monthly value is allocated evenly across all hours for all days in the month. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRTCAP $_{q,\ r}$	MW	*Reliability Must-Run Testing Capacity by hour*—The testing capacity of RMR Unit *r* represented by QSE *q*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRTA $_{q,\ r}$	none	*Reliability Must-Run Target Availability per QSE per Resource*—The Target Availability of RMR Unit *r* represented by QSE *q*, as specified in the RMR Agreement and divided by 100 to convert a percentage to a fraction. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRHREAF $_{q,\ r}$	none	*Reliability Must-Run Hourly Rolling Equivalent Availability Factor per QSE per Resource by hour*—The equivalent availability factor of RMR Unit *r* represented by QSE *q* over the current hour plus the prior 4379 hours for which availability is required under the RMR Agreement, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. The available capacity is calculated in accordance with paragraph (3) of Section 3.14.1.17.
RMRMNFNCC $_{q,\ r}$	\$	*Reliability Must-Run Monthly Non-Fuel Non-Capital Cost per QSE per Resource*—The actual non-capital and non-fuel Eligible Cost of RMR Unit *r* represented by QSE *q*, for the month. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRMNFCC $_{q,\ r}$	\$	*Reliability Must-Run Monthly Non-Fuel Capital Cost per QSE per Resource*—The actual non-fuel and capital Eligible Cost of RMR Unit *r* represented by QSE *q*, for the month. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Notwithstanding the above, reservation and transportation costs associated with firm fuel supplies as described in paragraph (1)(a)(vi) of Section 3.14.1.10, Eligible Costs, shall be included herein.
MH $_{q,\ r}$	hour	*Number of Hours in the Month per QSE per Resource*—The total number of hours of the month, when RMR Unit *r* represented by QSE *q* is under an RMR Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRIF	none	*Reliability Must Run Incentive Factor*—The Incentive Factor of RMR Units under RMR Agreement.
RMRARF $_{q,\ r}$	none	*Reliability Must-Run Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor of RMR Unit *r* represented by QSE *q*, as calculated for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition
$\text{HSL}_{q, r, hr}$	MW	*High Sustained Limit*—The High Sustained Limit (HSL) of a Generation Resource as defined in Section 2.1, Definitions, for the hour that includes the Settlement Interval *i*. Where for a combined cycle Resource, *r* is a Combined Cycle Generation Resource.
$\text{RMRAFLAG}_{q, r, hr}$	none	*RMR Availability Flag per QSE per Resource by hour*—The flag of the availability of RMR Unit *r* represented by QSE *q* as determined by the Current Operating Plan (COP), 1 for available and 0 for unavailable, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RMRTCAPA}_{q, r}$	MW	*Reliability Must-Run Testing Capacity Adjustment by hour*—The testing capacity adjustment factor, in the event an ERCOT Operator has deemed that a RMR Unit's Tested Capacity did not materially affect the reliability of the ERCOT System, of an RMR Unit *r* represented by QSE *q*, for the hour. See paragraph (2) of Section 3.14.1.17. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An RMR Unit.
hr	none	The index for a given hour and all the previous 4379 hours for which availability is required under the RMR Agreement.
4380	none	The number of hours in a six-month period.

(4) The total of the Standby Payments to each QSE for all RMR Units represented by this QSE for a given hour is calculated as follows:

$$\textbf{RMRSBAMTQSETOT}_{q} = \sum_{r} \textbf{RMRSBAMT}_{q, r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RMRSBAMTQSETOT}_{q}$	$	*Reliability Must-Run Standby Amount QSE Total per QSE*—The total of the Standby Payments to QSE *q* for all RMR Units represented by this QSE for the hour.
$\text{RMRSBAMT}_{q, r}$	$	*Reliability Must-Run Standby Payment per QSE per Resource*—The Standby Payment to QSE *q* for RMR Unit *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An RMR Unit.

6.6.6.2 RMR Payment for Energy

(1) Payment for energy on the Initial Settlement and settlements executed before true-up and before actual cost data is submitted must be calculated using the estimated input/output curve and startup fuel as specified in the RMR Agreement, the actual energy produced and the FIP. The payment for energy for all other settlements must be based on actual fuel costs for the RMR Unit. The payment for energy for each hour is calculated as follows:

$$\textbf{RMREAMT}_{q,r} = \textbf{(-1) * (((FIP + RMRCEFA}_{q,r}\textbf{) * RMRSUFQ}_{q,r}\textbf{ / RMRH}_{q,r}\textbf{) * RMRALLOCFLAG}_{q,r}\textbf{ + }\sum_{i=1}^{4}\textbf{(((FIP + RMRCEFA}_{q,r}\textbf{) * RMRHR}_{q,r,i}\textbf{ + RMRVCC}_{q,r}\textbf{) * RTMG}_{q,r,i}\textbf{))}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
RMREAMT $_{q,r}$	$	*Reliability Must-Run Energy Amount per QSE per Resource by hour*—The energy payment to QSE *q* for RMR Unit *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
FIP	$/MMBtu	*Fuel Index Price*—The FIP for the Operating Day.
RMRSUFQ $_{q,r}$	MMBtu	*Reliability Must-Run Startup Fuel Quantity per QSE per Resource*—The Estimated Start Up Fuel specified in the RMR Agreement for RMR Unit *r* represented by QSE *q*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRH $_{q,r,h}$	hour	*Reliability Must-Run Hours*—The number of hours during which RMR Unit *r* represented by QSE *q* is instructed On-Line for the Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRALLOCFLAG $_{q,r}$	none	*Reliability Must-Run Startup Flag per QSE per Resource by hour*—The number that indicates whether or not the startup fuel cost of RMR Unit *r* represented by QSE *q* is allocated to the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. The startup fuel cost will be allocated equally to all contiguous intervals for which there is an eligible start. The RMRALLOCFLAG $_{q,r}$ value is 1 if the startup fuel cost is allocated; otherwise, its value is 0. The RMRALLOCFLAG $_{q,r}$ for eligibility is determined in Sections 5.6.2, RUC Startup Cost Eligibility, and 5.6.3, Forced Outage of a RUC-Committed Resource, for start-up payments and commitments in either the Reliability Unit Commitment (RUC) or DAM.
RMRHR $_{q,r,i}$	MMBtu /MWh	*Reliability Must-Run Heat Rate per QSE per Resource by Settlement Interval by hour*—The multiplier determined based on the input/output curve and the Real-Time generation of RMR Unit *r* represented by QSE *q*, for the 15-minute Settlement Interval *i* in the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRVCC $_{q,r}$	$/MWh	*Reliability Must-Run Variable Cost Component per QSE per Resource*—The monthly cost component that is used to adjust the energy cost calculation to reflect the actual fuel costs of RMR Unit *r* represented by QSE *q*. The value is initially set to zero. For resettlements, see item (2) below. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMG $_{q,r,i,}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval by hour*—The Real-Time energy from RMR Unit *r* represented by QSE *q*, for the 15-minute Settlement Interval *i* in the hour *h*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRCEFA $_{q,r}$	$/MMBtu	*Reliability Must-Run Contractual Estimated Fuel Adder*—The Estimated Fuel Adder that is contractually agreed upon in Section 22, Attachment B, Standard Form Reliability Must-Run Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. The fuel adder will be subsequently trued up to reflect actual fuel costs as set forth in item (1) above.
q	none	A QSE.
r	none	An RMR Unit.

Variable	Unit	Definition
i	none	A 15-minute Settlement Interval.

(2) If the RMR actual fuel cost is filed in accordance with the timeline in these Protocols, the monthly RMR variable cost component is calculated for the subsequent resettlements as follows:

$$\textbf{RMRVCC}_{q,\,r} = (\textbf{RMRMFCOST}_{q,\,r} + \sum_{h} \textbf{RMREAMT}_{q,\,r,\,f,\,h}) \,/\, (\sum_{i} \textbf{RTMG}_{q,\,r,\,i})$$

The above variables are defined as follows:

Variable	Unit	Definition
RMRVCC $_{q,\,r}$	\$/MWh	*Reliability Must-Run Variable Cost Component per QSE per Resource*—The monthly cost component that is used to adjust the energy cost calculation to reflect the actual fuel costs of RMR Unit *r* represented by QSE *q*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRMFCOST $_{q,\,r}$	\$	*Reliability Must-Run Monthly actual Fuel Cost per QSE per Resource*—The monthly actual fuel cost of RMR Unit *r* represented by QSE *q*, for the month. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMG $_{q,\,r,\,i}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval*—The Real-Time energy from RMR Unit *r* represented by QSE *q* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMREAMT $_{q,\,r,\,f,\,h}$	\$	*Reliability Must-Run Energy Amount per QSE per Resource by hour*—The energy payment to QSE *q* for RMR Unit *r*, for the hour *h,* from the former Settlement Statement *f*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An RMR Unit.
h	none	An hour in the month.
i	none	A 15-minute Settlement Interval in the month.
f	none	Amount from former settlement run.

(3) The total of the payments for energy to each QSE for all RMR Units represented by this QSE for a given hour is calculated as follows:

$$\textbf{RMREAMTQSETOT}_{q} = \sum_{r} \textbf{RMREAMT}_{q,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
RMREAMTQSETOT $_{q}$	\$	*Reliability Must-Run Energy Amount QSE Total per QSE*—The total of the energy payments to QSE *q* for all RMR Units represented by this QSE for the hour.
RMREAMT $_{q,\,r}$	\$	*Reliability Must-Run Energy Amount per QSE per Resource by hour*—The energy payment to QSE *q* for RMR Unit *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

q	none	A QSE.
r	none	An RMR Unit.

6.6.6.3 RMR Adjustment Charge

(1) Each QSE that represents an RMR Unit shall pay a charge designed to recover the net total revenues from RUC settlements, and from Real-Time settlements received by that QSE for all RMR Units that it represents, except that the charge does not include net revenues received by the QSE for the RMR Standby Payments calculated under Section 6.6.6.1, RMR Standby Payment, and the RMR energy payments calculated under Section 6.6.6.2, RMR Payment for Energy.

(2) The charge for each QSE representing an RMR Unit for a given Operating Hour is calculated as follows:

$$\mathbf{RMRAAMT}_{q} = \mathbf{(-1) * [} \sum_{p} \sum_{r} \mathbf{((-1) *} \sum_{i=1}^{4} \mathbf{RESREV}_{q,\,r,\,gsc,\,p} + \sum_{i=1}^{4} \mathbf{EMREAMT}_{q,\,r,\,p,\,i} + \mathbf{RUCMWAMT}_{q,\,r,\,p} + \mathbf{RUCCBAMT}_{q,\,r,\,p} + \mathbf{RUCDCAMT}_{q,\,r,\,p} + \sum_{i=1}^{4} \mathbf{VSSEAMT}_{q,\,r,\,p,\,i} + \sum_{i=1}^{4} \mathbf{VSSVARAMT}_{q,\,r,\,i}\mathbf{)]}$$

The above variables are defined as follows:

Variable	Unit	Definition
RMRAAMT $_{q}$	$	*RMR Adjustment Charge per QSE*—The adjustment from QSE q Standby Payments and energy payments for all RMR Units represented by this QSE, for the revenues received for the same RMR Units from RUC and Real-Time operations, for the hour.
EMREAMT $_{q,\,r,\,p,\,i}$	$	*Emergency Energy Amount per QSE per Settlement Point per unit per interval*—The payment to QSE q for the additional energy produced by RMR Unit r at Resource Node p in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval i. Payment for emergency energy is made to the Combined Cycle Train. ***[NPRR1010 and NPRR1014: Replace applicable portions of the definition above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]*** *Emergency Energy Amount per QSE per Settlement Point per unit per interval*—The payment to QSE q as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource r at Resource Node p in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval i. Payment for emergency energy is made to the Combined Cycle Train.

Variable	Unit	Definition
$RESREV_{q, r, gsc, p}$	$	*Resource Share Revenue Settlement Payment*—The RMR Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*.
$RUCMWAMT_{q, r, p}$	$	*RUC Make-Whole Amount per QSE per Settlement Point per unit*—The amount calculated for RMR Unit *r* committed in RUC at Resource Node *p* to make whole the Startup Cost and minimum-energy cost of this unit, for the hour. See Section 5.7.1, RUC Make-Whole Payment. When one or more Combined Cycle Generation Resources are committed by RUC, payment is made to the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$RUCCBAMT_{q, r}$	$	*RUC Clawback Charge per QSE per unit*—The RUC Clawback Charge to QSE *q* for RMR Unit *r*, for the hour. See Section 5.7.2, RUC Clawback Charge. When one or more Combined Cycle Generation Resources are committed by RUC, a charge is made to the Combined Cycle Train for all RUC-committed Combined Cycle Generation Resources.
$RUCDCAMT_{q, r, p}$	$	*RUC Decommitment Amount per QSE per Settlement Point per unit*—The amount calculated for RMR Unit *r* at Resource Node *p* represented by QSE *q* due to ERCOT de-commitment, for the hour. When one or more Combined Cycle Generation Resources are decommitted by RUC, payment is made to the Combined Cycle Train for all RUC-decommitted Combined Cycle Generation Resources.
$VSSEAMT_{q, r, p, i}$	$	*Voltage Support Service Energy Amount per QSE per Settlement Point per unit per interval* —The compensation to QSE *q* for ERCOT-directed power reduction from RMR Unit *r* at Resource Node *p* to provide Voltage Support Service (VSS), for the 15-minute Settlement Interval *i*. Payment for VSS is made to the Combined Cycle Train.
$VSSVARAMT_{q, r, i}$	$	*Voltage Support Service VAr Amount per QSE per Unit*—The payment to QSE *q* for the VSS provided by RMR Unit *r*, for the 15-minute Settlement Interval *i*. Payment for VSS is made to the Combined Cycle Train.
q	none	A QSE.
gsc	none	A generation site code.
p	none	A Resource Node Settlement Point.
r	none	An RMR Unit.
i	none	A 15-minute Settlement Interval in the hour.

6.6.6.4 RMR Charge for Unexcused Misconduct

(1) If a Misconduct Event, as defined in the RMR Agreement, is not excused as provided in the RMR Agreement, then ERCOT shall charge the QSE that represents the RMR Unit an unexcused misconduct amount of $10,000 for each unexcused Misconduct Event as follows:

$$\mathbf{RMRNPAMT}_{q, r} = \mathbf{\$10{,}000 * RMRNPFLAG}_{q,r}$$

The above variable is defined as follows:

Variable	Unit	Definition
RMRNPAMT $_{q, r}$	$	*Reliability Must-Run Unexcused Misconduct Charge per QSE per Resource*—The charge to QSE *q* for the unexcused Misconduct Event of RMR Unit *r* for an Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RMRNPFLAG $_{q, r}$	$	*Reliability Must-Run Non-Performance Flag per QSE per Resource*—A flag for the QSE *q* for the unexcused Misconduct Event of RMR Unit *r* for an Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An RMR Unit.

(2) The total of the charges to each QSE for unexcused Misconduct Events of all RMR Units represented by this QSE for a given Operating Day is calculated as follows:

$$\mathbf{RMRNPAMTQSETOT}_{q} = \sum_{r} \mathbf{RMRNPAMT}_{q, r}$$

The above variables are defined as follows:

Variable	Unit	Definition
RMRNPAMTQSETOT $_{q}$	$	*Reliability Must-Run Unexcused Misconduct Amount QSE Total per QSE*—The total of the charges to QSE *q* for unexcused Misconduct Events of the RMR Units represented by this QSE for the Operating Day.
RMRNPAMT $_{q, r}$	$	*Reliability Must-Run Unexcused Misconduct Charge per QSE per Resource*—The charge to QSE *q* for the unexcused Misconduct Event of RMR Unit *r* for the Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An RMR Unit.

6.6.6.5 RMR Service Charge

(1) The total RMR cost for all RMR Units is allocated to the QSEs representing Loads based on LRS. The RMR Service charge to each QSE for a given hour is calculated as follows:

$$\begin{aligned}\mathbf{LARMRAMT}_{q} = {} & \mathbf{(-1) * (RMRSBAMTTOT + RMREAMTTOT} \\ & \mathbf{+ RMRAAMTTOT + RMRNPAMTTOT / H) * HLRS}_{q}\end{aligned}$$

Where:

RMR Standby Amount Total

$$\text{RMRSBAMTTOT} = \sum_{q} \text{RMRSBAMTQSETOT}_{q}$$

RMR Energy Amount Total

$$\text{RMREAMTTOT} = \sum_{q} \text{RMREAMTQSETOT}_{q}$$

RMR Adjustment Charge Total

$$\text{RMRAAMTTOT} = \sum_{q} \text{RMRAAMT}_{q}$$

RMR Non-Performance Amount Total

$$\text{RMRNPAMTTOT} = \sum_{q} \text{RMRNPAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LARMRAMT $_q$	$	*Load-Allocated Reliability Must-Run Amount per QSE*—The amount charged to QSE *q* based on its LRS of the difference between the amount paid to all QSEs for RMR Service under Section 6.6.6, Reliability Must-Run Settlement, and the amount that would have been paid to the QSEs for the same RMR Units if they were not providing RMR Service under the other parts of this Section 6, Adjustment Period and Real-Time Operations, and Section 5, Transmission Security Analysis and Reliability Unit Commitment.
RMRSBAMTTOT	$	*RMR Standby Amount Total*—The total of the Standby Payments to all QSEs for all RMR Units, for the hour.
RMREAMTTOT	$	*RMR Energy Amount Total*—The total of the energy cost payments to all QSEs for all RMR Units, for the hour.
RMRAAMTTOT	$	*RMR Adjusted Amount Total*—The total of the adjusted amounts from all QSEs representing RMR Units for the revenues received for these units from RUC, Real-Time operations and Ancillary Service markets, for the hour.
RMRNPAMTTOT	$	*RMR Non-Performance Amount Total*—The total of the charges to all QSEs for unexcused Misconduct Events of all RMR Units, for the Operating Day.
HLRS $_q$	none	The hourly LRS calculated for QSE *q* for the hour. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
RMRSBAMTQSETOT $_q$	$	*Reliability Must-Run Standby Amount QSE Total per QSE*—The total of the Standby Payments to QSE *q* for the RMR Units represented by the same QSE for the hour.
RMREAMTQSETOT $_q$	$	*Reliability Must-Run Energy Amount QSE Total per QSE*—The total of the energy payments to QSE *q* for the RMR Units represented by the same QSE for the hour.
RMRAAMT $_q$	$	*RMR Adjusted Amount per QSE*—The adjustment from QSE *q* Standby Payments and energy payments for all RMR Units represented by this QSE, for the revenues received for the same RMR Units from RUC and Real-Time operations, for the hour.
RMRNPAMTQSETOT $_q$	$	*Reliability Must-Run Unexcused Misconduct Amount QSE Total per QSE*—The total of the charges to QSE *q* for unexcused Misconduct Events of the RMR Units represented by the same QSE for the Operating Day.
q	none	A QSE.
H	none	The number of hours of the Operating Day.

6.6.6.6 Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred

Expenses

(1) No later than 30 days after the RTM True-Up Statement is issued for the termination date of the RMR Agreement, ERCOT shall issue a miscellaneous Invoice to charge the QSE representing the RMR Unit for any overpayments to the QSE representing the RMR Unit as described in Section 3.14.1.16, Reconciliation of Actual Eligible Costs, and contributed capital expenditures described in Section 3.14.1.19, Charge for Contributed Capital Expenditures. Refunded contributed capital expenditures are prorated evenly and on a monthly basis over the RMR Agreement period before being allocated to Load on an hourly LRS basis. Refunded overpayments described in Section 3.14.1.16 are allocated directly to the month in which the overpayment occurred before being allocated to Load on an hourly LRS basis. A separate Invoice will be sent for each RMR Agreement.

(a) The one-time charge to the QSE to collect the lump sum of over-payments and contributed capital expenditures is calculated as follows:

$$\text{RMRRAMT}_{q, r, c} = \text{RMRCE}_{q, r, c} + \sum_{m} \text{RMROP}_{q, r, c, m}$$

(b) The one-time payment is calculated as follows:

$$\text{LARMRRAMT}_{q} = (-1) * \sum_{m} (\text{MRMRCE}_{m} + \text{RMROP}_{q, r, c, m}) / \text{MH}_{m} * \text{HLRS}_{q, m}$$

Where:

$$\text{MRMRCE}_{m} = \sum_{q} \sum_{r} \text{RMRCE}_{q, r, c} / \text{CM}_{q, r, c}$$

The HLRS used will be the HLRS for each day within the contracted month *m*. The most recent approved HLRS available at time the miscellaneous Invoice is posted will be used. The miscellaneous Invoice will not be re-calculated with subsequent Settlement runs unless required by a dispute or Alternative Dispute Resolution (ADR). If a dispute or ADR requires ERCOT to re-issue the miscellaneous Invoice, the most recent approved HLRS values will be used.

(c) Upon issuance of the miscellaneous Invoice, ERCOT shall issue a Market Notice containing the values of RMROP, RMRCE, and the Settlement run containing the HLRS that was used in the Settlement.

The above variables are defined as follows:

Variable	**Unit**	**Description**
RMRRAMT $_{q, r, c}$	$	*Reliability Must-Run Reconciled Amount* – The lump sum charge to the QSE *q* representing the RMR Unit *r* that reconciles any contributed

		capital expenditure amounts and any over-payments to the QSE during the period of the RMR Agreement *c*.
RMRCE $_{q, r, c}$	$	*Reliability Must-Run Capital Expenditure Refund*– The lump sum amount of contributed capital expenditures for the QSE *q* representing the RMR Unit *r* for the period of the RMR Agreement *c* to be refunded to ERCOT per Section 3.14.1.19.
RMROP $_{q, r, c, m}$	$	*Reliability Must-Run Over-Payment* – The amount of overpayments to the QSE *q* representing the RMR Unit *r* for the month *m* during the period of the RMR Agreement *c* to be refunded to ERCOT per Section 3.14.1.19. This amount cannot be negative.
MRMRCE $_{m}$	$	*Monthly Reliability Must-Run Capital Expenditure Refund* – The lump sum amount of contributed capital expenditures for the month *m* refunded to ERCOT per Section 3.14.1.19 pro-rated over the number of months of the RMR Agreement.
LARMRRAMT $_{q}$	$	*Load Allocated Reliability Must-Run Reconciled Amount* – The amount of refunded capital expenditures paid to QSE *q* based on its HLRS.
HLRS $_{q, m}$	none	*Hourly Load Ratio Share per QSE* – The hourly LRS calculated for QSE *q* for the hour for month *m*. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
MH $_{m}$	hour	*Number of Hours in the Month* —The total number of hours in the month *m*, which overlaps a month in which an RMR Agreement was effective. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
CM $_{q, r, c}$	none	The number of months of the RMR Agreement period.
m	none	A month in the RMR Agreement period.
q	none	A QSE.
c	none	An RMR Agreement.
r	none	An RMR Unit.

(2) ERCOT shall issue a miscellaneous Invoice allocating expenses incurred related to the processing of an RMR Agreement or validation and/or processing of RMR budgets on an LRS basis. ERCOT shall issue the miscellaneous Invoice no later than 30 days after the RTM True-Up Statement is issued for the last day of the calendar month in which ERCOT incurred the expense. A separate Invoice will be sent for each RMR Agreement.

(a) The one-time charge is calculated as follows:

$$\text{LARMROEIAMT}_{q} = (-1) * \sum_{m} \text{RMROEIAMT}_{m} / \text{MH}_{m} * \text{HLRS}_{q, m}$$

The HLRS used will be the HLRS for each day within the contracted month *m*. The most recent approved HLRS available at the time the miscellaneous Invoice is posted will be used. The miscellaneous Invoice will not be re-calculated with subsequent Settlement runs unless required by a dispute or ADR. If a dispute or ADR requires ERCOT to re-issue the miscellaneous Invoice, the most recent approved HLRS values will be used.

(b) Upon issuance of the miscellaneous Invoice, ERCOT shall issue a Market Notice containing the value of RMROEIAMT and the Settlement run containing the HLRS that was used in the Settlement.

The above variables are defined as follows:

Variable	**Unit**	**Description**
RMROEIAMT_{m}	$	*RMR Other Expense Incurred Amount* – The amount of expenses incurred in the validation and processing of an RMR Agreement, for the month *m*, that are not paid to the QSE representing the RMR Unit e.g. third-party expenses incurred in the evaluation and validation of submitted RMR budgets.
LARMROEIAMT_{q}	$	*Load Allocated RMR Other Expense Incurred Amount* – The amount of other expenses incurred charged to QSE *q* based on its HLRS.
$\text{HLRS}_{q, m}$	none	*Hourly Load Ratio Share per QSE* – The hourly LRS calculated for QSE *q* for the hour for month *m*. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
MH_{m}	hour	*Number of Hours in the Month* —The total number of hours in the month *m*, which overlaps a month in which an RMR Agreement was effective.
m	none	A month in the RMR Agreement period.
q	none	A QSE.
r	none	An RMR Unit.

(3) ERCOT shall collect and distribute Must-Run Alternative (MRA) contributed capital expenditures described in Section 3.14.1.19 as follows:

(a) The one-time charge to the QSE to collect the lump sum of contributed capital expenditures will be reflected as:

$$\text{MRACERAMT}_{q, r, c}$$

(b) The one-time payment is calculated as follows:

$$\text{LAMRACERAMT}_{q} = (-1) * \sum_{M} \sum_{D} \text{MMRACER} / \text{MH}_{q, r} * \text{HLRS}_{q}$$

Where:

$$\text{MMRACER} = \text{MRACERAMT}_{q, r, c} / \text{CM}_{q, r, c}$$

The HLRS used will be the HLRS for each day within the contracted month M. The most recent approved HLRS available at time the miscellaneous Invoice is posted will be used. The miscellaneous Invoice will not be re-calculated with subsequent Settlement runs unless required by a dispute or ADR. If a dispute or ADR requires ERCOT to re-issue the miscellaneous Invoice, the most recent approved HLRS values will be used.

The above variables are defined as follows:

Variable	Unit	Description
$MRACERAMT_{q, r, c}$	$	*Must-Run Alternative Capital Expenditure Refund Amount* – The lump sum amount of contributed capital expenditures refunded to ERCOT per Section 3.14.1.19.
MMRACER	$	*Monthly Must-Run Alternative Capital Expenditure Refund* – The lump sum amount of contributed capital expenditures refunded to ERCOT per Section 3.14.1.19 pro-rated over the number of months of the MRA Agreement.
$LAMRACERAMT_{q}$	$	*Load Allocated Must-Run Alternative Capital Expenditure Refund Amount* – The amount of refunded capital expenditures paid to QSE *q* based on its HLRS.
$HLRS_{q}$	none	*Hourly Load Ratio Share per QSE* – The hourly LRS calculated for QSE *q* for the hour for month M. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
$MH_{q, r}$	hour	*Number of Hours in the Month per QSE per Resource*—The total number of hours in the month, when MRA *r* represented by QSE *q* is under an MRA Agreement. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
$CM_{q, r, c}$	none	The number of months of the MRA Agreement period.
M	none	A month in the MRA Agreement period.
D	none	The number of days in the month.
q	none	A QSE.
c	none	An MRA Agreement.
r	none	An MRA.

[NPRR885: Insert Section 6.6.6.7 below upon system implementation:]

6.6.6.7 MRA Standby Payment

(1) The Standby Payment for MRA Service is paid to each QSE representing an MRA for each MRA Contracted Hour under performance requirements set forth in Section 22, Attachment N, Standard Form Must-Run Alternative Agreement, the MRA Request for Proposal (RFP), and the Protocols.

(2) The standby payment to each QSE representing a Generation Resource MRA registered is calculated as follows for each hour:

$$MRASBAMT_{q, r, h} = (-1) * MRASBPR_{q, r, m} * MRACCAP_{q, r, m} * MRAGRCRF_{q, r, m} * MRAARF_{q, r, m}$$

Where:

$$MRAGRCRF_{q, r, m} = (MRATCAP_{q, r, m} + MRATCAPA_{q, r, m}) / MRACCAP_{q, r, m}$$

(3) The standby payment to each QSE representing an Other Generation MRA or Demand Response MRA is calculated as follows for each hour:

$$\text{MRASBAMT}_{q,\,r,\,h} = (-1) * \text{MRASBPR}_{q,\,r,\,m} * \text{MRACCAP}_{q,\,r,\,m} * \text{MRAEPRF}_{q,\,r,\,m} * \text{MRAARF}_{q,\,r,\,m}$$

(4) The MRA Capacity Availability Reduction Factor (MRAARF) is calculated as:

For initial Settlement

$$\text{MRAARF}_{q,\,r,\,m} = 1$$

For all other resettlements

If $\text{MRACMAF}_{q,\,r,\,m} \geq 95\% * \text{MRATA}_{q,\,r,\,m}$

$$\text{MRAARF}_{q,\,r,\,m} = 1$$

If $85\% * \text{MRATA}_{q,\,r,\,m} \leq \text{MRACMAF}_{q,\,r,m} < 95\% * \text{MRATA}_{q,\,r,\,m}$

$$\text{MRAARF}_{q,\,r,\,m} = \text{MRACMAF}_{q,\,r,\,m}$$

If $\text{MRACMAF}_{q,\,r,\,m} < 85\% * \text{MRATA}_{q,\,r,\,m}$

$$\text{MRAARF}_{q,\,r,\,m} = (\text{MRACMAF}_{q,\,r,\,m})^2$$

Where:

For an MRA registered as a Generation Resource,

$$\text{MRACMAF}_{q,\,r,\,m} = \sum_{h} (\text{MRAMAH}_{q,\,r,\,h}) / (\text{MH}_{q,\,r,\,m})$$

And,

For an MRA not registered as a Generation Resource, the availability factor is calculated pursuant to Section 3.14.4.6.4, MRA Availability Measurement and Verification.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{MRASBAMT}_{q,\,r,\,h}$	\$	*Must-Run Alternative Standby Amount per QSE per Resource by hour*—The hourly standby payment amount for MRA *r* represented by QSE *q*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
$\text{MRASBPR}_{q,\,r,\,m}$	\$/MW per hour	*Must-Run Alternative Standby Price per QSE per Resource per MW per hour*—The hourly standby price per MW for MRA *r* represented by QSE *q*, for the month *m*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.

MRAEPRF $_{q,\ r,\ m}$	None	*Must-Run Alternative Event Performance Reduction Factor per QSE per Resource*—The Event Performance Reduction Factor of the MRA *r* represented by QSE *q*, for each hour of the month m, as calculated per Section 3.14.4.6.5, MRA Event Performance Measurement and Verification. If the MRAEPRF for the month is not available then the most recent MRAEPRF prior to month of the Operating Day shall be used. If no previous MRAEPRF is available then MRAEPRF shall be set to 1. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRAGRCRF $_{q,\ r,\ m}$	None	*Must-Run Alternative Generation Resource Capacity Reduction Factor per QSE per Resource per month* —The capacity reduction factor of the Generation Resource MRA *r* represented by QSE *q*, for each hour of the month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRACCAP $_{q,\ r,\ m}$	MW	*Must-Run Alternative Contract Capacity per QSE per Resource*—The capacity of MRA *r* represented by QSE *q* as specified in the MRA Agreement, for the MRA Contracted Month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRAARF $_{q,\ r,\ m}$	None	*Must-Run Alternative Availability Reduction Factor per QSE per Resource*—The availability reduction factor of MRA *r* represented by QSE *q*, for each hour of the MRA Contracted Month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRATCAPA $_{q,\ r,\ m}$	MW	*Must-Run Alternative Testing Capacity Adjustment per month*—The testing capacity adjustment factor of an MRA *r* represented by QSE *q*, for each hour of the MRA Contracted Month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRATCAP $_{q,\ r,\ m}$	MW	*Must-Run Alternative Testing Capacity per month*—The testing capacity value of MRA *r* represented by QSE *q*, for each hour of the MRA Contracted Month *m*. If the MRATCAP for the month is not available then the most recent MRATCAP prior to month of the Operating Day shall be used. If no previous MRATCAP is available, then MRATCAP shall be set to MRACCAP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
MRATA $_{q,\ r,\ m}$	None	*Must-Run Alternative Target Availability per QSE per Resource per Month*—The monthly Target Availability of MRA *r* represented by QSE *q*, as specified in the MRA Agreement and divided by 100 to convert a percentage to a fraction. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
MRACMAF $_{q,\ r,\ m}$	None	*Must-Run Alternative Calculated Monthly Availability Factor per QSE per Resource*—The calculated monthly availability factor of MRA *r* represented by QSE *q*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRAMAH $_{q,\ r,\ h}$	Hour	*Number of Available Hours in the Month per QSE per Resource*— For an MRA registered as a Generation Resource, the total number of hours in the month when the MRA *r* represented by QSE *q* was available for the MRA Contracted Hours if the MRA's Availability Plan and telemetry both indicate availability for that hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MH $_{q,\ r,\ m}$	Hour	*Number of Total MRA Contracted Hours in the Month per QSE per Resource*—The total number of MRA Contracted Hours in the month for the MRA *r* represented by QSE *q* as indicated in the MRA Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
h	None	A MRA Contracted Hour under the MRA Agreement for the MRA Contracted month.
q	None	A QSE.

r	None	An MRA.
m	None	An MRA Contracted Month under the MRA Agreement.

(5) The total of the Standby Payments for all MRAs represented by the QSE for a given hour is calculated as follows:

$$\text{MRASBAMTQSETOT}_{q} = \sum_{r} \text{MRASBAMT}_{q,\,r,\,h}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
MRASBAMTQSETOT $_{q}$	$	*Must-Run Alternative Standby Amount Total per QSE per hour* — The total of the Standby Payments for all MRAs represented by the QSE *q* for the hour.
MRASBAMT $_{q,\,r,\,h}$	$	*Must-Run Alternative Standby Amount per QSE per Resource by hour* — The hourly standby payment amount for MRA *r* represented by QSE *q*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
q	None	A QSE.
r	None	An MRA.
h	None	An MRA Contracted Hour under the MRA Agreement for the calendar month.

(6) The total of the Standby Payments for a given hour is calculated as follows:

$$\text{MRASBAMTTOT} = \sum_{q} \text{MRASBAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
MRASBAMTTOT	$	*Must-Run Alternative Standby Amount Total* —The total of the Standby Payments to all QSEs *q* for all MRAs for the hour.
MRASBAMTQSETOT $_{q}$	$	*Must-Run Alternative Standby Amount Total per QSE per hour* —The total of the Standby Payments for all MRAs represented by the QSE *q* for the hour.
q	None	A QSE.

[NPRR885: Insert Section 6.6.6.8 below upon system implementation:]

6.6.6.8 MRA Contributed Capital Expenditures Payment

(1) The contributed capital expenditure payment to each QSE for each MRA for each MRA Contracted Hour of each month is calculated as follows:

$$\mathbf{MRACAPEXAMT}_{q,\,r} = (-1) * \mathbf{MRAMCAPEX}_{q,\,r,\,m} / \mathbf{MH}_{q,\,r,\,m}$$

The above variables are defined as follows:

Variable	Unit	Definition
$MRACAPEXAMT_{q,\,r}$	$	*Must-Run Alternative Contributed Capital Expenditures Amount per QSE per Resource per hour*— The total monthly contributed capital expenditure payment for MRA *r* represented by QSE *q*, allocated to each MRA Contracted Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
$MRAMCAPEX_{q,\,r,\,m}$	$	*Must-Run Alternative Monthly Contributed Capital Expenditures per QSE*—The total monthly contributed capital expenditures for MRA *r* represented by QSE *q*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
$MH_{q,\,r,\,m}$	hour	*Number of Total Contracted Hours in the Month per QSE per Resource*—The total number of MRA Contracted Hours in the MRA Contracted Month *m* for the MRA *r* represented by QSE *q* as indicated in the MRA Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.
m	none	An MRA Contracted Month under the MRA Agreement.

(2) The total of the contributed capital expenditure payments for all MRAs represented by the QSE for a given hour is calculated as follows:

$$\mathbf{MRACAPEXAMTQSETOT}_{q} = \sum_{r} \mathbf{MRACAPEXAMT}_{q,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$MRACAPEXAMTQSETOT_{q}$	$	*Must-Run Alternative Contributed Capital Expenditures per QSE per hour* – The total contributed capital expenditures for all MRAs *r* represented by QSE *q* for the MRA Contracted Hour.
$MRACAPEXAMT_{q,\,r}$	$	*Must-Run Alternative Contributed Capital Expenditures Amount per QSE per Resource* – The total monthly contributed capital expenditure payment for MRA *r* represented by QSE q, allocated to each MRA Contracted Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.

(3) The total contributed capital expenditure payments for a given MRA Contracted Hour is calculated as follows:

$$\mathbf{MRACAPEXAMTTOT} = \sum_{q} \mathbf{MRACAPEXAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRACAPEXAMTTOT	$	*Must-Run Alternative Contributed Capital Expenditures per hour* – The total contributed capital expenditures to all QSEs for all MRAs for the MRA Contracted Hour.

$MRACAPEXAMTQSETOT_{q}$	$	*Must-Run Alternative Contributed Capital Expenditures per QSE per hour* – The total contributed capital expenditures for all MRAs represented by QSE *q* for the MRA Contracted Hour.
q	none	A QSE.

[NPRR885: Insert Section 6.6.6.9 below upon system implementation:]

6.6.6.9 MRA Payment for Deployment Event

(1) The deployment event payment to each QSE representing a Generation Resource MRA:

$$MRADEAMT_{q, r, h} = (-1) * Max\{EDPRICE_{q, r, m}, (FIP + MRACEFA_{q, r}) * MRAPSUFQ_{q, r}\} * MRAFLAG_{q, r, h} / MRAH_{q, r}$$

(2) The deployment event payment to each QSE representing a Demand Response MRA or Other Generation MRA:

$$MRADEAMT_{q, r, h} = (-1) * Max\{EDPRICE_{q, r}, (FIP + MRACEFA_{q, r}) * MRAPSUFQ_{q, r}\} * MRAEPRF_{q, r, m} / MRAH_{q, r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$MRADEAMT_{q, r, h}$	$	*Must-Run Alternative Deployment Event Amount per QSE per Resource by hour*—The deployment event payment to QSE *q* for MRA *r*, for the MRA Contracted Hour *h*. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
FIP	$/MMBtu	*Fuel Index Price*—The FIP for the Operating Day.
$EDPRICE_{q, r}$	$	*Event Deployment Price per QSE per Resource*—The event deployment price to QSE *q* for MRA *r*, as specified in the MRA Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MRAEPRF_{q, r, m}$	None	*Must-Run Alternative Event Performance Reduction Factor per QSE per Resource* —The event performance reduction factor of the MRA *r* represented by QSE *q*, for each hour of the month *m*, as calculated per Section 3.14.4.6.5, MRA Event Performance Measurement and Verification. If the MRAEPRF for the month is not available then the most recent MRAEPRF prior to the month of the Operating Day shall be used. If no previous MRAEPRF is available then MRAEPRF shall be set to 1. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MRAPSUFQ_{q, r}$	MMBtu	*Must-Run Alternative Proxy Startup Fuel Quantity per QSE per Resource*—The proxy start up fuel quantity specified in the MRA Agreement for MRA *r* represented by QSE *q*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MRAH_{q, r}$	Hour	*Must-Run Alternative Hours*—The number of hours during which MRA *r* represented by QSE *q* received a deployment instruction for each deployment event for the Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

$\text{MRAFLAG}_{q, r, h}$	none	*Must-Run Alternative Flag* – An indicator to signify that an MRA *r* represented by QSE *q* followed the deployment instruction for the event for the hour *h*. An MRAFLAG value of 1 represents followed and a 0 represents did not follow the deployment. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{MRACEFA}_{q, r}$	$/MMBtu	*Must-Run Alternative Contractual Estimated Fuel Adder*—The Estimated Fuel Adder for the MRA *r* represented by QSE *q* as specified in the MRA Agreement. Where for a Combined Cycle Train, the Generation Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.
m	none	An MRA Contracted Month under the MRA Agreement.
h	none	An MRA Contracted Hour under the MRA Agreement for the MRA Contracted Month.

(3) The total of the deployment event payments for all MRAs represented by the QSE for a given MRA Contracted Hour is calculated as follows:

$$\text{MRADEAMTQSETOT}_{q} = \sum_{r} \text{MRADEAMT}_{q, r, h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{MRADEAMTQSETOT}_{q}$	$	*Must-Run Alternative Deployment Event Amount per QSE by hour*—The total of the deployment event payments for all MRAs *r*, represented by the QSE q for the hour.
$\text{MRADEAMT}_{q, r, h}$	$	*Must-Run Alternative Deployment Event Amount per QSE per Resource by hour*—The deployment event payment to QSE *q* for MRA *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.
h	none	An MRA Contracted Hour under the MRA Agreement for the MRA Contracted Month.

(4) The total of the deployment event payments for a given MRA Contracted Hour is calculated as follows:

$$\text{MRADEAMTTOT} = \sum_{q} \text{MRADEAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRADEAMTTOT	$	*Must-Run Alternative Deployment Event Amount Total by hour*—The total deployment event payment to all QSEs for all MRAs, for the hour.
$\text{MRADEAMTQSETOT}_{q}$	$	*Must-Run Alternative Deployment Event Amount per QSE by hour*—The total of the deployment event payments for all MRAs represented by the QSE *q* for the MRA Contracted Hour.

q	none	A QSE.

[NPRR885, NPRR1010, and NPRR1014: Insert applicable portions of Section 6.6.6.10 below upon system implementation for NPRR885 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.6.10 MRA Variable Payment for Deployment

(1) The variable payment to each QSE representing a Generation Resource MRA:

Outside of the MRA Contracted Hours, a Generation Resource MRA shall be treated in Settlements in the same manner as any Generation Resource registered with ERCOT

For MRA Contracted Hours with a deployment instruction:

$$\text{MRAVAMT}_{q,\,r,\,h} = (-1) * (\text{MRAGRCVP}_{q,\,r,\,h} - \text{MRARTREV}_{q,\,r,\,h})$$

For MRA Contracted Hours without a deployment instruction:

$$\text{MRAVAMT}_{q,\,r,\,h} = (-1) * (\text{Min}\,(\text{MRAGRCVP}_{q,\,r,\,h}, \text{MRARTREV}_{q,\,r,\,h}) - \text{MRARTREV}_{q,\,r,\,h})$$

Where,

$$\text{MRAGRCVP}_{q,\,r,\,h} = \sum_{i=1}^{4} \text{Max}\,[\text{VPRICE}_{q,\,r}, (\text{FIP} + \text{MRACEFA}_{q,\,r}) * \text{MRAPHR}_{q,\,r}] * \text{Min}(\text{RTMG}_{q,\,r,\,p,\,i}, \text{MRACCAP}_{q,\,r,\,m} / 4)$$

$$\text{MRARTREV}_{q,r,h} = \sum_{i=1}^{4} \text{Max}\,[0, (\text{RESREV}_{q,\,r,\,gsc,\,p,\,i} + (-1) * (\text{EMREAMT}_{q,\,r,\,p,\,i} + \text{VSSVARAMT}_{q,\,r,\,i} + \text{VSSEAMT}_{q,\,r,\,i}))]$$

(2) The variable payment to each QSE representing an Other Generation MRA:

For MRA Contracted Hours with a deployment instruction:

$$\text{MRAVAMT}_{q,\,r,\,h} = (-1) * (\text{MRACVP}_{q,\,r,\,h} - \text{MRACRTREV}_{q,\,r,\,h})$$

For MRA Contracted Hours without a deployment instruction:

$$\text{MRAVAMT}_{q,\,r,h} = (-1) * (\text{Min}(\text{MRACVP}_{q,\,r,\,h}, \text{MRACRTREV}_{q,\,r,\,h}) - \text{MRACRTREV}_{q,\,r,\,h})$$

Where,

$$\text{MRACVP}_{q,\,r,\,h} = \sum_{i=1}^{4} \text{Max}[\text{VPRICE}_{q,\,r}, (\text{FIP} + \text{MRACEFA}_{q,\,r}) * \text{MRAPHR}_{q,\,r}] *$$

$$\text{RTVQ}_{q,\,r,\,i}$$

$$\text{MRACRTREV}_{q,\,r,\,h} = \sum_{i=1}^{4} (\text{Max}(0, \text{Min}(\text{RTVQ}_{q,\,r,\,i}, \text{MRACCAP}_{q,\,r,\,m} / 4) * \text{RTSPP}_{p,\,i}))$$

Where,

$$\text{RTVQ}_{q,\,r,\,i} = \text{MRAIPF}_{q,\,r,i} * \text{MRACCAP}_{q,\,r,\,m} / 4$$

(3) The variable payment to each QSE representing a Demand Response MRA:

For MRA Contracted Hours with a deployment instruction:

$$\text{MRAVAMT}_{q,\,r,\,h} = (-1) * \sum_{i=1}^{4} \text{Max}[\text{VPRICE}_{q,\,r}, (\text{FIP} + \text{MRACEFA}_{q,\,r}) * \text{MRAPHR}_{q,\,r}] * \text{RTVQ}_{q,\,r,\,i}$$

Where,

$$\text{RTVQ}_{q,\,r,\,i} = \text{MRAIPF}_{q,\,r,i} * \text{MRACCAP}_{q,\,r,\,m} / 4$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{MRAVAMT}_{q,\,r,\,h}$	$	*Must-Run Alternative Variable Amount per QSE per Resource by hour*—The variable payment to QSE *q* for MRA *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{MRAGRCVP}_{q,\,r,\,h}$	$	*Must-Run Alternative Generation Resource Calculated Variable Payment per QSE per Resource* - The variable payment to QSE *q* for Generation Resource MRA *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
FIP	$/MMBtu	*Fuel Index Price*—The FIP for the Operating Day.
$\text{MRARTREV}_{q,\,r,\,h}$	$	*Must-Run Alternative Real-Time Revenues per QSE per Resource by hour*—The revenues received in Real-Time for QSE *q* for MRA *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{MRACCAP}_{q,\,r,\,m}$	MW	*Must-Run Alternative Contract Capacity per QSE per Resource*—The capacity of MRA *r* represented by QSE *q* as specified in the MRA Agreement, for the month. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{MRAIPF}_{q,\,r,\,i}$	none	*Must-Run Alternative Interval Performance Factor per QSE per Resource for the interval*— The interval performance factor of the MRA *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
$\text{MRACVP}_{q,\,r,h}$	$	*Must-Run Alternative Calculated Variable Payment per QSE per Resource* - The variable payment to QSE *q* for an Other Generation MRA or Demand Response MRA *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

VSSVARAMT $_{q, r, i}$	$	*Voltage Support Service VAr Amount per QSE per Generation Resource -* The payment to QSE *q* for the VSS provided by Generation Resource MRA *r*, for the 15-minute Settlement Interval *i*. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSEAMT $_{q, r, i}$	$	*Voltage Support Service Energy Amount per QSE per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource MRA *r* for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
RESREV $_{q, r, gsc, p, i}$	$	*Resource Share Revenue Settlement Payment*—The Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Generation Resource MRA *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
EMREAMT $_{q, r, p, i}$	$	*Emergency Energy Amount per QSE per Settlement Point per unit per interval*—The payment to QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource MRA *r* at Resource Node *p* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval *i*. Payment for emergency energy is made to the Combined Cycle Train.
VPRICE $_{q, r}$	$/MWh	*Must-Run Alternative Variable Price per QSE per Resource*—The variable price for QSE *q* for MRA *r*, as specified in the MRA Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRAPHR $_{q, r}$	MMBtu /MWh	*Must-Run Alternative Proxy Heat Rate per QSE per Resource – A proxy heat rate value for* MRA *r* represented by QSE *q, as* specified in the MRA Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRACRTREV $_{q, r, h}$	$	*Must-Run Alternative Calculated Real-Time Revenues per QSE per Resource* —The calculated variable revenue to QSE *q* for MRA *r*, for the hour.
RTVQ $_{q, r, i,}$	MWh	*Real-Time Variable Quantity per QSE per Resource by Settlement Interval* — The Real-Time variable quantity for MRA *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
RTMG $_{q, r, p, i}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Generation Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRACEFA $_{q, r}$	$/MMBtu	*Must-Run Alternative Contractual Estimated Fuel Adder*—The Estimated Fuel Adder that is contractually agreed upon in Section 22, Attachment N, Standard Form Must-Run Alternative Agreement. Where for a Combined Cycle Train, the Generation Resource *r* is the Combined Cycle Train.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	An MRA.
m	none	An MRA Contracted Month.
h	none	An MRA Contracted Hour for the MRA Contracted Month.
i	none	A 15-minute Settlement Interval during the MRA Contracted Hours.
gsc	none	A generation site code.

p	none	A Resource Node Settlement Point.

(2) The total of the variable payments for all MRAs represented by the QSE for a given hour is calculated as follows:

$$\text{MRAVAMTQSETOT}_{q} = \sum_{r} \text{MRAVAMT}_{q, r, h}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRAVAMTQSETOT_{q}	$	*Must-Run Alternative Variable Amount Total per QSE by hour*—The total variable payment for all MRAs *r,* represented by the QSE *q*, for the hour.
$\text{MRAVAMT}_{q, r, h}$	$	*Must-Run Alternative Variable Amount per QSE per Resource by hour*—The variable payment to QSE *q* representing MRA *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.
h	none	An MRA Contracted Hour for the MRA Contracted Month.

(3) The total of the variable payments for a given MRA Contracted Hour is calculated as follows:

$$\text{MRAVAMTTOT} = \sum_{q} \text{MRAVAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRAVAMTTOT	$	*Must-Run Alternative Variable Amount Total by hour*—The total variable payments for the MRA Contracted Hour.
MRAVAMTQSETOT_{q}	$	*Must-Run Alternative Variable Amount Total per QSE by hour*—The total variable payment for all MRAs*,* represented by the QSE *q*, for the MRA Contracted Hour.
q	none	A QSE.

[NPRR885: Insert Section 6.6.6.11 below upon system implementation:]

6.6.6.11 MRA Charge for Unexcused Misconduct

(1) If one or more Misconduct Events are not excused, as provided for in Section 3.14.4.8, MRA Misconduct Events, then ERCOT shall charge the QSE that represents the MRA an unexcused misconduct amount for the Operating Day as follows:

$$\text{MRAUMAMT}_{q, r,h} = \$10{,}000 * \text{MRAUMFLAG}_{q, r, d} / \text{MRACH}_{q, r, d}$$

The above variable is defined as follows:

Variable	Unit	Definition
$\text{MRAUMAMT}_{q, r, h}$	$	*Must-Run Alternative Unexcused Misconduct Charge per QSE per Resource*—The charge to QSE *q* for the unexcused Misconduct Event of MRA *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{MRAUMFLAG}_{q, r, d}$	none	*Must-Run Alternative Unexcused Misconduct Flag per QSE per Resource*—A flag for the QSE *q* for the unexcused Misconduct Event of MRA *r* for an Operating Day *d*. The MRAUMFLAG of MRA represented by QSE *q*, 1 for a unexcused misconduct and 0 for none, for the day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{MRACH}_{q, r, d}$	hour	*Must-Run Alternative Contract Hours in the Operating Day* – The number of MRA Contracted Hours for QSE *q* for the MRA *r* for an Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.
d	none	An Operating Day within a month under an MRA Agreement
h	none	An MRA Contracted Hour for the MRA Contracted Month.

(2) The total of the charges to each QSE for unexcused Misconduct Events of all MRAs represented by this QSE for a given hour is calculated as follows:

$$\text{MRAUMAMTQSETOT}_{q} = \sum_{r} \text{MRAUMAMT}_{q, r, h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{MRAUMAMTQSETOT}_{q}$	$	*Must-Run Alternative Unexcused Misconduct Amount per QSE*—The total of the charges to QSE *q* for unexcused Misconduct Events of the MRAs for an MRA Contracted Hour.
$\text{MRAUMAMT}_{q, r, h}$	$	*Must-Run Alternative Unexcused Misconduct Charge per QSE per Resource*—The charge to QSE *q* for the unexcused Misconduct Event of MRA *r* for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An MRA.
h	none	An MRA Contracted Hour for the MRA Contracted Month.

(3) The total of the charges to all QSEs for unexcused Misconduct Events of all MRAs for an MRA Contracted Hour is calculated as follows:

$$\text{MRAUMAMTTOT} = \sum_{q} \text{MRAUMAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRAUMAMTTOT	$	*Must-Run Alternative Unexcused Misconduct Amount Total per hour* —The total of the charges for unexcused Misconduct Events for the hour.
MRAUMAMTQSETOT_q	$	*Must-Run Alternative Unexcused Misconduct Amount per QSE*—The total of the charges to QSE *q* for unexcused Misconduct Events of the MRAs for an MRA Contracted Hour.
q	none	A QSE.

[NPRR885: Insert Section 6.6.6.12 below upon system implementation:]

6.6.6.12 MRA Service Charge

(1) The total MRA cost for all MRAs is allocated to the QSEs representing Loads based on HLRS. The MRA Service charge to each QSE for a given hour is calculated as follows:

$$\text{LAMRAAMT}_q = (-1) * (\text{MRASBAMTTOT} + \text{MRACAPEXAMTTOT} + \text{MRADEAMTTOT} + \text{MRAVAMTTOT} + \text{MRAUMAMTTOT}) * \text{HLRS}_q$$

The above variables are defined as follows:

Variable	Unit	Definition
LAMRAAMT_q	$	*Load-Allocated Must-Run Alternative Amount per QSE*—The MRA cost allocated to QSE *q* based on its HLRS.
MRASBAMTTOT	$	*Must-Run Alternative Standby Amount Total* —The total of the Standby Payments to all QSEs *q* for all MRAs for the hour.
MRACAPEXAMTTOT	$	*Must-Run Alternative Contributed Capital Expenditures per hour* - The total contributed capital expenditures to all QSEs *q* for all MRAs *r* for the hour.
MRADEAMTTOT	$	*Must-Run Alternative Deployment Event Amount Total by hour*—The total deployment event payment to all QSEs *q* for all MRAs *r*, for the hour.
MRAVAMTTOT	$	*Must-Run Alternative Variable Amount Total by hour*—The total variable payments for the hour.
MRAUMAMTTOT	$	*Must-Run Alternative Unexcused Misconduct Amount Total per hour* —The total of the charges for unexcused Misconduct Events for the hour.
HLRS_q	none	*The hourly LRS calculated for QSE q for the hour*. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
q	none	A QSE.

6.6.7 Voltage Support Settlement

6.6.7.1 Voltage Support Service Payments

(1) All other Generation Resources shall be eligible for compensation for Reactive Power production in accordance with Section 6.5.7.7, Voltage Support Service, only if ERCOT issues a Dispatch Instruction that results in the following unit operation:

   (a) When ERCOT instructs the Generation Resource to exceed its Unit Reactive Limit (URL) and the Generation Resource provides additional Reactive Power, then ERCOT shall pay for the additional Reactive Power provided at a price that recognizes the avoided cost of reactive support Resources on the transmission network.

   (b) Any real power reduction directed by ERCOT through VDIs to provide for additional reactive capability for voltage support must be compensated as a lost opportunity payment

(2) The payment for a given 15-minute Settlement Interval to each QSE representing a Generation Resource that operates in accordance with an ERCOT Dispatch Instruction is calculated as follows:

Depending on the Dispatch Instruction, payment for Volt-Amperes reactive (VAr):

If $\text{VSSVARLAG}_{q,\,r} > 0$

$$\textbf{VSSVARAMT}_{\boldsymbol{q,\,r}} = \textbf{(-1) * VSSVARPR * VSSVARLAG}_{\boldsymbol{q,\,r}}$$

If $\text{VSSVARLEAD}_{q,\,r} > 0$

$$\textbf{VSSVARAMT}_{\boldsymbol{q,\,r}} = \textbf{(-1) * VSSVARPR * VSSVARLEAD}_{\boldsymbol{q,\,r}}$$

Where:

$\text{VSSVARLAG}_{q,\,r}$ = $\text{Max}\,[0, \text{Min}\,(¼ * \text{VSSVARIOL}_{q,\,r}, \text{RTVAR}_{q,\,r}) - (¼ * \text{URLLAG}_{q,\,r})]$

$\text{VSSVARLEAD}_{q,\,r}$ = $\text{Max}\,\{0, [(¼ * \text{URLLEAD}_{q,\,r}) - \text{Max}\,((¼ * \text{VSSVARIOL}_{q,\,r}), \text{RTVAR}_{q,\,r})]\}$

$\text{URLLAG}_{q,r}$ = $0.32868 * \text{HSL}_{q,r}$

$\text{URLLEAD}_{q,r}$ = $(-1) * 0.32868 * \text{HSL}_{q,r}$

The above variables are defined as follows:

Variable	Unit	Definition
VSSVARAMT $_{q,\ r}$	$	*Voltage Support Service VAr Amount per QSE per Generation Resource* - The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARPR	$/MVArh	*Voltage Support Service VAr Price* - The price for instructed MVAr beyond a Generation Resource's URL currently is $2.65/MVArh (based on $50.00/installed kVAr).
VSSVARLAG $_{q,\ r}$	MVArh	*Voltage Support Service VAr Lagging per QSE per Generation Resource* - The instructed portion of the Reactive Power above the Generation Resource's lagging URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARLEAD $_{q,\ r}$	MVArh	*Voltage Support Service VAr Leading per QSE per Generation Resource* - The instructed portion of the Reactive Power below the Generation Resource's leading URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARIOL $_{q,\ r}$	MVAr	*Voltage Support Service VAr Instructed Output Level per QSE per Generation Resource*—The instructed Reactive Power output level of Generation Resource *r* represented by QSE *q*, lagging Reactive Power if positive and leading Reactive Power if negative, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
RTVAR $_{q,\ r}$	MVArh	*Real-Time VAr per QSE per Resource*—The netted Reactive Energy measured for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
URLLAG $_{q,\ r}$	MVAr	*Unit Reactive Limit Lagging per QSE per Resource*—The URL for lagging Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is positive. Where for a combined cycle resource, *r* is a Combined Cycle Train.
URLLEAD $_{q,\ r}$	MVAr	*Unit Reactive Limit Leading per QSE per Resource*—The URL for leading Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is negative. Where for a combined cycle resource, *r* is a Combined Cycle Train.
HSL $_{q,\ r}$	MW	*High Sustained Limit*—The HSL of a Generation Resource as defined in Section 2, Definitions and Acronyms, for the hour that includes the Settlement Interval *i*. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
q	none	A QSE.
r	none	A Generation Resource.

(3) The total additional compensation to each QSE for VSS for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{VSSVARAMTQSETOT_q} = \sum_{r} \mathbf{VSSVARAMT}_{\boldsymbol{q,r}}$$

Variable	Unit	Definition
$VSSVARAMT_{q, r}$	$	*Voltage Support Service VAr Amount per QSE per Generation Resource*—The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
$VSSVARAMTQSETOT_{q}$	$	*Voltage Support VAr Amount QSE total per QSE*—The total of the payments to QSE *q* as compensation for VSS by this QSE for the 15-minute Settlement Interval.
q	none	A QSE.
r	none	A Generation Resource.

(4) The lost opportunity payment, if applicable:

$$\mathbf{VSSEAMT_{q, r} = (-1) * Max (0, (RTSPP_{p} - RTEOCOST_{q, r, i}) * Max (0, (HSL_{q, r} * 1/4 - RTMG_{q, r})))}$$

The above variables are defined as follows:

Variable	Unit	Definition
$VSSEAMT_{q, r}$	$	*Voltage Support Service Energy Amount per QSE per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource *r* for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
$RTMG_{q, r}$	MWh	*Real-Time Metered Generation per QSE per Resource*—The Real-Time metered generation of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource Node for the 15-minute Settlement Interval.
$RTEOCOST_{q, r, i}$	$/MWh	*Real-Time Energy Offer Curve Cost*—The Energy Offer Curve Cost for Resource *r* represented by QSE *q*, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Costs. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$HSL_{q, r}$	MW	*High Sustained Limit Generation per QSE per Settlement Point per Resource*—The HSL of Generation Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
$LSL_{q, r}$	MW	*Low Sustained Limit Generation per QSE per Settlement Point per Resource*—The LSL of Generation Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.

(5) The total of the payments to each QSE for ERCOT-directed power reduction to provide VSS for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{VSSEAMTQSETOT}_{q} = \sum_{r} \textbf{VSSEAMT}_{q,\,r}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
VSSEAMTQSETOT $_{q}$	$	*Voltage Support Service Lost Opportunity Amount QSE Total per QSE*—The total of the lost opportunity payments to QSE *q* for providing VSS for providing ERCOT-directed VSS for the 15-minute Settlement Interval.
VSSEAMT $_{q,\,r}$	$	*Voltage Support Service Energy Amount per QSE per Settlement Point per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource *r* for the 15-minute Settlement Interval for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
q	none	A QSE.
r	none	A Generation Resource.

[NPRR1014: Replace Section 6.6.7.1 above with the following upon system implementation:]

6.6.7.1 Voltage Support Service Payments

(1) All other Generation Resources or ESRs shall be eligible for compensation for Reactive Power production in accordance with Section 6.5.7.7, Voltage Support Service, only if ERCOT issues a Dispatch Instruction that results in the following unit operation:

(a) When ERCOT instructs the Generation Resource or ESR to exceed its Unit Reactive Limit (URL) and the Generation Resource or ESR provides additional Reactive Power, then ERCOT shall pay for the additional Reactive Power provided at a price that recognizes the avoided cost of reactive support Resources on the transmission network.

(b) Any real power reduction directed by ERCOT through VDIs to provide for additional reactive capability for voltage support must be compensated as a lost opportunity payment

(2) The payment for a given 15-minute Settlement Interval to each QSE representing a Generation Resource or ESR that operates in accordance with an ERCOT Dispatch Instruction is calculated as follows:

Depending on the Dispatch Instruction, payment for Volt-Amperes reactive (VAr):

If $\text{VSSVARLAG}_{q,\,r} > 0$

$$\textbf{VSSVARAMT}_{q,\,r} = \textbf{(-1) * VSSVARPR * VSSVARLAG}_{q,\,r}$$

If $\text{VSSVARLEAD}_{q,\,r} > 0$

$$\textbf{VSSVARAMT}_{\boldsymbol{q,\,r}} = \textbf{(-1) * VSSVARPR * VSSVARLEAD}_{\boldsymbol{q,\,r}}$$

Where:

$$\text{VSSVARLAG}_{q,\,r} = \text{Max}\ [0, \text{Min}\ (\tfrac{1}{4} * \text{VSSVARIOL}_{q,\,r}, \text{RTVAR}_{q,\,r}) - (\tfrac{1}{4} * \text{URLLAG}_{q,\,r})]$$

$$\text{VSSVARLEAD}_{q,\,r} = \text{Max}\ \left\{0, [(\tfrac{1}{4} * \text{URLLEAD}_{q,\,r}) - \text{Max}\ ((\tfrac{1}{4} * \text{VSSVARIOL}_{q,\,r}), \text{RTVAR}_{q,\,r})]\right\}$$

And:

If an ESR has a net withdrawal for the Settlement Interval, then:

$$\text{URLLAG}_{q,r} = 0.32868 * \text{ABS}(\text{LSL}_{q,r})$$

$$\text{URLLEAD}_{q,r} = (-1) * 0.32868 * \text{ABS}(\text{LSL}_{q,r})$$

Otherwise:

$$\text{URLLAG}_{q,r} = 0.32868 * \text{HSL}_{q,r}$$

$$\text{URLLEAD}_{q,r} = (-1) * 0.32868 * \text{HSL}_{q,r}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{VSSVARAMT}_{q,\,r}$	$	*Voltage Support Service VAr Amount per QSE per Resource* - The payment to QSE *q* for the VSS provided by Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARPR	$/MVArh	*Voltage Support Service VAr Price* - The price for instructed MVAr beyond a Resource's URL currently is $2.65/MVArh (based on $50.00/installed kVAr).
$\text{VSSVARLAG}_{q,\,r}$	MVArh	*Voltage Support Service VAr Lagging per QSE per Resource* - The instructed portion of the Reactive Power above the Generation Resource's lagging URL for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
$\text{VSSVARLEAD}_{q,\,r}$	MVArh	*Voltage Support Service VAr Leading per QSE per Resource* - The instructed portion of the Reactive Power below the Resource's leading URL for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.

VSSVARIOL $_{q,\,r}$	MVAr	*Voltage Support Service VAr Instructed Output Level per QSE per Resource*—The instructed Reactive Power output level of Resource *r* represented by QSE *q*, lagging Reactive Power if positive and leading Reactive Power if negative, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
RTVAR $_{q,\,r}$	MVArh	*Real-Time VAr per QSE per Resource*—The netted Reactive Energy measured for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
URLLAG $_{q,\,r}$	MVAr	*Unit Reactive Limit Lagging per QSE per Resource*—The URL for lagging Reactive Power of the Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is positive. Where for a combined cycle resource, *r* is a Combined Cycle Train.
URLLEAD $_{q,\,r}$	MVAr	*Unit Reactive Limit Leading per QSE per Resource*—The URL for leading Reactive Power of the Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is negative. Where for a combined cycle resource, *r* is a Combined Cycle Train.
HSL $_{q,\,r}$	MW	*High Sustained Limit*—The HSL of Resource *r* represented by QSE *q* as defined in Section 2, Definitions and Acronyms, for the hour that includes the Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
LSL $_{q,\,r}$	MW	*Low Sustained Limit*—The LSL for Resource *r* represented by QSE *q*, as defined in Section 2, for the hour that includes the Settlement Interval.
q	none	A QSE.
r	none	A Generation Resource or ESR.

(3) The total additional compensation to each QSE for voltage support service for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{VSSVARAMTQSETOT_q = \sum_{r} VSSVARAMT}_{\boldsymbol{q,r}}$$

Variable	Unit	Definition
VSSVARAMT $_{q,\,r}$	$	*Voltage Support Service VAr Amount per QSE per Resource*—The payment to QSE *q* for the VSS provided by Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
VSSVARAMTQSETOT $_{q}$	$	*Voltage Support VAr Amount QSE total per QSE*—The total of the payments to QSE *q* as compensation for VSS by this QSE for the 15-minute settlement interval.
q	None	A QSE.
r	None	A Generation Resource or ESR.

(4) The lost opportunity payment, if applicable:

If an ESR has a net withdrawal for the Settlement Interval, then:

$$\textbf{VSSEAMT}_{q,\,r} = \textbf{(-1) * Max (0, RTSPP}_{p}\textbf{) * Max (0, (ABS(LSL}_{q,\,r}\textbf{ * ¼ - NETVSSA}_{q,\,r}\textbf{)))}$$

Otherwise:

$$\textbf{VSSEAMT}_{q,\,r} = \textbf{(-1) * Max (0, (RTSPP}_{p}\textbf{ – RTEOCOST}_{q,\,r,\,i}\textbf{) * Max (0, (HSL}_{q,\,r}\textbf{ * ¼ - NETVSSA}_{q,\,r}\textbf{)))}$$

Where:

$$\text{NETVSSA}_{q,\,r} = \text{RTCL}_{q,\,r} + \text{RTMG}_{q,\,r}$$

For an ESR that is not a WSL:

$$\text{RTCL}_{q,\,r} = \sum_{b} \text{MEBR}_{q,\,r,\,b}$$

And for an ESR that is a WSL:

$$\text{RTCL}_{q,\,r} = \sum_{b} \text{MEBL}_{q,\,r,\,b}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{VSSEAMT}_{q,\,r}$	$	*Voltage Support Service Energy Amount per QSE per Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Resource *r* for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
$\text{RTMG}_{q,\,r}$	MWh	*Real-Time Metered Generation per QSE per Resource*—The Real-Time metered generation of Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
RTSPP_{p}	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource Node for the 15-minute Settlement Interval.
$\text{RTEOCOST}_{q,\,r,\,i}$	$/MWh	Real-Time Energy Offer Curve Cost - The Energy Offer Curve Cost for Resource *r* represented by QSE *q*, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Costs. Where for an ESR, RTEOCOST shall be set to zero. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{NETVSSA}_{q,\,r}$	MWh	*Net VSS Activity*—The sum of the total energy metered by the Settlement Meter which measures ESR load and the RTMG, for Resource *r* represented by the QSE *q* for the 15-minute Settlement Interval.
$\text{RTCL}_{q,\,r}$	MWh	*Real-Time Charging Load per QSE per Resource* —The charging load for Resource *r* represented by the QSE *q*, represented as a negative value, for the 15-minute Settlement Interval.
$\text{MEBL}_{q,\,r,\,b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.

MEBR $_{q, r, b}$	MWh	*Metered Energy for Energy Storage Resource load at Bus* - The energy metered by the Settlement Meter which measures ESR load that is not WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
HSL $_{q, r}$	MW	*High Sustained Limit per QSE per Settlement Point per Resource*—The HSL of Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
LSL $_{q, r}$	MW	*Low Sustained Limit per QSE per Settlement Point per Resource*—The LSL of Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource.
q	none	A QSE.
r	none	A Generation Resource or ESR.
p	none	A Resource Node Settlement Point.
b	none	An Electrical Bus.

(5) The total of the payments to each QSE for ERCOT-directed power reduction to provide VSS for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{VSSEAMTQSETOT}_{\boldsymbol{q}} = \sum_{r} \textbf{VSSEAMT}_{\boldsymbol{q, r}}$$

The above variables are defined as follows:

Variable	Unit	Definition
VSSEAMTQSETOT $_{q}$	$	*Voltage Support Service Lost Opportunity Amount QSE Total per QSE*—The total of the lost opportunity payments to QSE *q* for providing VSS for providing ERCOT-directed VSS for the 15-minute Settlement Interval.
VSSEAMT $_{q, r}$	$	*Voltage Support Service Energy Amount per QSE per Settlement Point per Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Resource *r* for the 15-minute Settlement Interval for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train.
q	none	A QSE.
r	none	A Generation Resource or ESR.

6.6.7.2 Voltage Support Charge

(1) ERCOT shall charge each QSE representing LSEs the total payment for VSS as specified in Section 6.6.7.1, Voltage Support Service Payments, based on a LRS. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{LAVSSAMT}_{\boldsymbol{q}} = \textbf{(-1) * (VSSVARAMTTOT + VSSEAMTTOT) * LRS}_{\boldsymbol{q}}$$

Where:

$$\text{VSSVARAMTTOT} = \sum_{q} \text{VSSVARAMTQSETOT}_{q}$$

$$\text{VSSEAMTTOT} = \sum_{q} \text{VSSEAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LAVSSAMT $_{q}$	$	*Load-Allocated Voltage Support Service Amount per QSE*—The charge to QSE *q* for VSS, for the 15-minute Settlement Interval.
VSSVARAMTTOT	$	*Voltage Support Service var Amount Total*—The total of payments to all QSEs providing VSS, for the 15-minute Settlement Interval.
VSSVARAMTQSETOT $_{q}$	$	*Voltage Support Service var Amount QSE Total per QSE*—The total of the payments to QSE *q* for providing VSS for the 15-minute Settlement Interval.
LRS $_{q}$	none	*The Load Ratio Share* calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
VSSEAMTTOT	$	*Voltage Support Service Lost Opportunity Amount Total*—The total of payments to all QSEs providing VSS in lieu of energy, for the 15-minute Settlement Interval.
VSSEAMTQSETOT $_{q}$	$	*Voltage Support Service Lost Opportunity Amount QSE Total per QSE*—The total of the payments to QSE *q* for providing VSS in lieu of energy, for the 15-minute Settlement Interval.
q	none	A QSE.

6.6.8 Black Start Capacity

6.6.8.1 Black Start Hourly Standby Fee Payment

(1) ERCOT shall pay an Hourly Standby Fee to the QSEs representing a Black Start Resource. This standby fee is determined through a competitive bi-annual bidding process, with an adjustment for reliability based on a six-month rolling availability equal to 85% in accordance with Section 22, Attachment D, Standard Form Black Start Agreement.

(2) The Black Start Hourly Standby Fee is subject to reduction and claw-back provisions as described in Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing.

(3) ERCOT shall pay a Black Start Hourly Standby Fee payment to each QSE for each Black Start Resource. The payment for each hour is calculated as follows:

$$\mathbf{BSSAMT}_{q,\,r} = (-1) * \mathbf{BSSPR}_{q,\,r} * \mathbf{BSSARF}_{q,\,r}$$

Where:

Black Start Service Availability Reduction Factor

If ($\text{BSSHREAF}_{q,\,r} \geq 0.85$)

$\text{BSSARF}_{q,\,r} = 1$

Otherwise

$$\text{BSSARF}_{q,\,r} \quad = \quad \text{Max}\,(0,\, 1 - (0.85 - \text{BSSHREAF}_{q,\,r}) * 2)$$

Black Start Service Hourly Rolling Equivalent Availability Factor

If ($\text{BSSEH}_{q,\,r} < 4380$)

$$\text{BSSHREAF}_{q,\,r} \quad = \quad 1$$

Otherwise

$$\text{BSSHREAF}_{q,\,r} \quad = \quad (\sum_{hr=h-4379}^{h} \text{BSSAFLAG}_{q,r,hr}) / 4380$$

Availability for a Combined Cycle Train will be determined pursuant to contractual terms but no more than once per hour.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{BSSAMT}_{q,\,r}$	$	*Black Start Service Amount per QSE per Resource by hour*—The standby payment to QSE *q* for the Black Start Service (BSS) provided by Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{BSSPR}_{q,\,r}$	$ per hour	*Black Start Service Price per QSE per Resource*—The standby price of BSS Resource *r* represented by QSE *q*, as specified in the Black Start Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{BSSARF}_{q,\,r}$	none	*Black Start Service Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor of Resource *r* represented by QSE *q* under the Black Start Agreement, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{BSSHREAF}_{q,\,r}$	none	*Black Start Service Hourly Rolling Equivalent Availability Factor per QSE per Resource by hour*—The equivalent availability factor of the BSS Resource *r* represented by QSE *q* over 4,380 hours, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{BSSEH}_{q,\,r}$	none	*Black Start Service Elapsed number of Hours per QSE per Resource by hour*—The number of the elapsed hours of BSS Resource *r* represented by QSE *q* since the beginning of the BSS Agreement, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{BSSAFLAG}_{q,\,r,\,hr}$	none	*Black Start Service Availability Flag per QSE per Resource by hour*—The flag of the availability of BSS Resource *r* represented by QSE *q*, 1 for available and 0 for unavailable, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
q	none	A QSE.
r	none	A BSS Resource.
hr	none	The index of a given hour and the previous 4379 hours.
4380	none	The number of hours in a six-month period.

(3) The total of the payments to each QSE for all BSS Resources represented by this QSE for a given hour is calculated as follows:

$$\mathbf{BSSAMTQSETOT}_{q} \quad = \quad \sum_{r} \mathbf{BSSAMT}_{q,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
BSSAMTQSETOT_{q}	$	*Black Start Service Amount QSE Total per QSE*—The total of the payments to QSE *q* for BSS provided by all the BSS Resources represented by this QSE for the hour *h*.
$\text{BSSAMT}_{q,\,r}$	$	*Black Start Service Amount per QSE per Resource*—The standby payment to QSE *q* for BSS provided by Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A BSS Resource.

6.6.8.2 Black Start Capacity Charge

(1) ERCOT shall allocate the total Black Start Service Capacity payment to the QSEs representing Loads based on a LRS. The resulting charge to each QSE for a given hour is calculated as follows:

$$\mathbf{LABSSAMT}_{q} = \quad \mathbf{(-1) * BSSAMTTOT * HLRS}_{q}$$

Where:

$$\text{BSSAMTTOT} = \quad \sum_{q} \text{BSSAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LABSSAMT_{q}	$	*Load-Allocated Black Start Service Amount per QSE*—The charge allocated to QSE *q* for the BSS, for the hour.
BSSAMTQSETOT_{q}	$	*Black Start Service Amount QSE Total per QSE*—The Black Start Service payment to QSE *q* for BSS Resource *r*, for the hour.
BSSAMTTOT	$	*Black Start Service Amount QSE Total ERCOT-Wide* — The total of the payments to QSE *q* for BSS provided by all the BSS Resource represented by this QSE for the hour h.
HLRS_{q}	none	The hourly LRS calculated for QSE *q* for the hour. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
q	none	A QSE.

6.6.9 Emergency Operations Settlement

(1) Due to Emergency Conditions or Watches, additional compensation for each Generation Resource for which ERCOT provides an Emergency Base Point may be awarded to the QSE representing the Generation Resource. If the Emergency Base Point is higher than the SCED Base Point immediately before the Emergency Condition or Watch and the Settlement Point Price at the Resource Node is lower than the Generation Resource's Energy Offer Curve price at the Emergency Base Point, ERCOT shall pay the QSE additional compensation for the additional energy above the SCED Base Point.

(2) In accordance with paragraph (8) of Section 8.1.1.2, General Capacity Testing Requirements, QSEs that receive a VDI to operate the designated Generation Resource for an unannounced Generation Resource test may be considered for additional compensation utilizing the formula as stated in Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT. If the test period SCED Base Point is higher than the SCED Base Point immediately before the test period and the Settlement Point Price at the Resource Node is lower than the Generation Resource's Energy Offer Curve price, or MOC if no offer exists, at the test Base Point, and the test was not a retest requested by the QSE, ERCOT shall pay the QSE additional compensation for the additional energy above the pre-test SCED Base Point. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the unannounced Generation Resource test, SCED Base Points will be used in place of the Emergency Base Point.

(3) A QSE that represents a QSGR that comes On-Line as a result of a Base Point greater than zero shall be considered for additional compensation using the formula in Section 6.6.9.1 when the Base Point is less than or equal to its applicable Seasonal net minimum sustainable rating provided in the Resource Registration data. If the Resource Settlement Point Price at the QSGR's Resource Node is lower than the Energy Offer Curve price, capped per the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap, at the aggregated Base Point during the 15-minute Settlement Interval, ERCOT shall pay the QSE additional compensation for the amount of energy from the Off-Line zero Base Point to the aggregated output level. For the purpose of this Settlement, inclusive of the first Settlement Interval in which the QSGR is deployed by SCED from a current SCED Base Point equal to zero MW to a Base Point greater than zero, SCED Base Points will be used in place of the Emergency Base Point. The compensation specified in this paragraph continues over all applicable Intervals until SCED no longer needs the QSGR to generate energy pursuant to Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process, and there is no manual Low Dispatch Limit (LDL) override in place on the QSGR.

(4) QSEs that received Base Points that are inconsistent with Real-Time Settlement Point Prices and QSEs that receive a manual override from the ERCOT Operator shall be considered for additional compensation using the formula in Section 6.6.9.1. If the Resource Settlement Point Price at the Resource Node is lower than the Energy Offer Curve price, capped per the MOC pursuant to Section 4.4.9.4.1, at the held Base Point during the 15-minute Settlement Interval, ERCOT shall pay the QSE additional compensation for the amount of energy from a zero Base Point to the held Base Point. The held Base Point is the Base Point that the QSE received due to a manual override by ERCOT Operator or the Base Point received by the QSE that ERCOT identified as inconsistent with Real-Time Settlement Point Prices. For the purpose of this Settlement, and limited to the held Settlement Intervals inclusive of the manual override or Base Points identified as inconsistent with prices, SCED Base Points will be used in place of the Emergency Base Point.

(5) In accordance with Section 6.3, Adjustment Period and Real-Time Operations Timeline, if ERCOT sets any SCED interval as failed, then QSEs shall be considered for additional compensation using the formula in Section 6.6.9.1. For the purpose of this Settlement,

and limited to the failed SCED interval, SCED Base Points will be used in place of the Emergency Base Point.

(6) For each 15-minute Settlement Interval, a QSGR that receives a manual override from the ERCOT Operator shall only be considered for compensation under paragraph (4) above.

(7) For a QSGR, the MOC curve used to cap the Energy Offer Curve shall not include the variable Operations and Maintenance (O&M) adjustment cost to start the Resource from first fire to LSL, including the startup fuel described in paragraph (1)(c) of Section 4.4.9.4.1 for all emergency operations Settlement calculations with the exception of paragraph (3) above.

(8) QSEs that receive a VDI to operate its Resources for an unannounced CFC test, as described in the ERCOT Operating Guides, or have been instructed to operate in CFC mode, may be considered for additional compensation utilizing the formula in Section 6.6.9.1. If the Resource Settlement Point Price at the Resource Node is lower than the Energy Offer Curve price, capped per the MOC pursuant to Section 4.4.9.4.1, at the Emergency Base Point during the CFC period, ERCOT shall pay the QSE additional compensation for the amount of energy from a zero Base Point to the Emergency Base Point for each Resource that provided CFC. Compensation for a CFC test will not be provided if the test was a retest requested by the QSE. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the CFC period, the Emergency Base Point shall be set to the Average Telemetered Generation for the 5 Minutes (AVGTG5M). Only Resources that moved in the direction to correct frequency are eligible to receive compensation for providing CFC.

(9) If Emergency Base Points or SCED Base Points are unavailable, corrupted or otherwise unusable for Settlement purposes due to system conditions, hardware failure, or software failure, the Real-Time Metered Generation (RTMG) will be used to create proxy Base Points pursuant to Section 6.6.9.1. If the RTMG is not available the most accurate available generation data as determined by ERCOT will be used to create proxy Base Points pursuant to Section 6.6.9.1. ERCOT shall issue a Market Notice stating the Operating Day and Settlement Intervals that were impacted and the generation data that was used to create proxy Base Points.

[NPRR1010, NPRR1014, and NPRR1058: Replace applicable portions of Section 6.6.9 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1058:]

6.6.9 Emergency Operations Settlement

(1) Due to Emergency Conditions or Watches, additional compensation for each Generation Resource or Energy Storage Resource (ESR) for which ERCOT provides an Emergency Base Point may be awarded to the QSE representing the Generation Resource or ESR. If the Resource was instructed to increase generation at a Settlement

Point price that is lower than the price based on their Energy Offer Curve or Energy Bid/Offer Curve, or if the Resource was instructed to increase withdrawal at a Settlement Point price that is higher than the price based on their Energy Bid/Offer Curve, ERCOT shall pay the QSE additional compensation for the change from the SCED Base Point immediately before the Emergency Condition or Watch, per paragraph (1) in Section 6.6.9.1, Payment for Emergency Operations Settlement. The Energy Offer Curve and Energy/Bid Offer Curve shall be capped by the Mitigated Offer Cap (MOC).

(2) In accordance with paragraph (8) of Section 8.1.1.2, General Capacity Testing Requirements, QSEs that receive a VDI to operate the designated Generation Resource for an unannounced Generation Resource test may be considered for additional compensation utilizing the formula as stated in paragraph (1) in Section 6.6.9.1. If the test period SCED Base Point is higher than the SCED Base Point immediately before the test period and the Settlement Point Price at the Resource Node is lower than the Generation Resource's Energy Offer Curve price, or MOC if no offer exists, at the test Base Point, and the test was not a retest requested by the QSE, ERCOT shall pay the QSE additional compensation for the additional energy above the pre-test SCED Base Point. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the unannounced Generation Resource test, SCED Base Points will be used in place of the Emergency Base Point.

(3) A QSE that represents a QSGR that comes On-Line as a result of a Base Point greater than zero shall be considered for additional compensation using the formula in paragraph (2) in Section 6.6.9.1 when the Base Point is less than or equal to its applicable Seasonal net minimum sustainable rating provided in the Resource Registration data. For the 15-minute Settlement Interval, the process for additional compensation compares the Resource's energy and Ancillary Services revenue with the Resource's revenue target, as defined in Section 6.6.9.1, considering both Ancillary Service awards and Base Points, where the Energy Offer Curve is capped per the MOC. For the purpose of this Settlement, inclusive of the first Settlement Interval in which the QSGR is deployed by SCED from a current SCED Base Point equal to zero MW to a Base Point greater than zero, SCED Base Points will be used in place of the Emergency Base Point. The compensation specified in this paragraph continues over all applicable Intervals until SCED no longer needs the QSGR to generate energy pursuant to Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process, and there is no manual Low Dispatch Limit (LDL) override in place on the QSGR.

(4) QSEs that received Base Points that are inconsistent with Real-Time Settlement Point Prices and QSEs that receive a manual override from the ERCOT Operator shall be considered for additional compensation using the formula in paragraph (2) in Section 6.6.9.1. For the 15-minute Settlement Interval, the process for additional compensation compares the Resource's energy and Ancillary Services revenue with the Resource's revenue target, as defined in Section 6.6.9.1, considering both the Ancillary Service awards and held Base Points, where the Energy Offer Curve or the

Energy Bid/Offer Curve is capped per the MOC. The held Base Point is the Base Point that the QSE received due to a manual override by ERCOT Operator or the Base Point received by the QSE that ERCOT identified as inconsistent with Real-Time Settlement Point Prices. For the purpose of this Settlement, and limited to the held Settlement Intervals inclusive of the manual override or Base Points identified as inconsistent with prices, SCED Base Points will be used in place of the Emergency Base Point.

(5) In accordance with Section 6.3, Adjustment Period and Real-Time Operations Timeline, if ERCOT sets any SCED interval as failed, then QSEs shall be considered for additional compensation using the formula in paragraph (1) in Section 6.6.9.1. For the purpose of this Settlement, and limited to the failed SCED interval, SCED Base Points will be used in place of the Emergency Base Point.

(6) For each 15-minute Settlement Interval, a QSGR that receives a manual override from the ERCOT Operator shall only be considered for compensation under paragraph (4) above.

(7) For a QSGR, the MOC curve used to cap the Energy Offer Curve shall not include the variable Operations and Maintenance (O&M) adjustment cost to start the Resource from first fire to LSL, including the startup fuel described in paragraph (1)(d) of Section 4.4.9.4.1 for all emergency operations Settlement calculations with the exception of paragraph (3) above.

(8) Any QSE that receives a VDI to operate its Resource for an unannounced CFC test, as described in the ERCOT Operating Guides, or that has been instructed to operate in CFC mode, may be considered for additional compensation utilizing the formula in paragraph (1) in Section 6.6.9.1. If the Resource increased generation at a Settlement Point Price that is lower than the price based on the Energy Offer Curve or Energy Bid/Offer Curve, or if the Resource was instructed to increase withdrawal at a Settlement Point Price that is higher than the price based on its Energy Bid/Offer Curve, ERCOT shall pay the QSE additional compensation for the amount of energy from a zero Base Point to the Emergency Base Point for each Resource that provided CFC. Compensation for a CFC test will not be provided if the test was a retest requested by the QSE. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the CFC period, the Emergency Base Point shall be set to the Average Telemetered Generation for the 5 Minutes (AVGTG5M) and the Energy Offer Curve and Energy/Bid Offer Curve shall be capped by the MOC. Only Resources that moved in the direction to correct frequency are eligible to receive compensation for providing CFC.

(9) If Emergency Base Points or SCED Base Points are unavailable, corrupted or otherwise unusable for Settlement purposes due to system conditions, hardware failure, or software failure, the Real-Time Metered Generation (RTMG) and Real-Time Charging Load (RTCL) will be used to create proxy Base Points pursuant to Section 6.6.9.1. If the RTMG and RTCL are not available, the most accurate available generation and withdrawal data as determined by ERCOT will be used to create proxy

Base Points pursuant to Section 6.6.9.1. ERCOT shall issue a Market Notice stating the Operating Day and Settlement Intervals that were impacted and the generation data that was used to create proxy Base Points.

(10) The Energy Offer Curve or Energy Bid/Offer Curve used to calculate the Emergency Base Point Price (EBPPR) will be the Energy Offer Curve or Energy Bid/Offer Curve that was submitted by the QSE and effective for the applicable Operating Hour at the time of the triggering event that led to emergency Settlement consideration, except when the QSE has received Base Points that are inconsistent with Real-Time Settlement Point Prices, as described in paragraph (4) above. In the case of the condition described in paragraph (3) above, the triggering event would be the first interval in which the QSGR comes On-Line as a result of a Base Point greater than zero.

(11) For ESRs that qualify for emergency Settlement, for purposes of this section, the MOC curve used to cap the Energy Bid/Offer Curve shall be set to the highest Real-Time Settlement Point Price (RTSPP) at the Resource's Settlement Point for the Operating Day.

6.6.9.1 Payment for Emergency Power Increase Directed by ERCOT

(1) If the Emergency Base Point issued to a Generation Resource is higher than the SCED Base Point immediately before the Emergency Condition or Watch, then ERCOT shall pay the QSE an additional compensation for the Resource at its Resource Node Settlement Point. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{EMREAMT}_{\boldsymbol{q, r, p}} = \mathbf{(-1) * EMREPR}_{\boldsymbol{q, r, p}} \mathbf{* EMRE}_{\boldsymbol{q, r, p}}$$

Where:

$$\text{EMREPR}_{q, r, p} = \text{Max}\ (0, \text{EBPWAPR}_{q, r, p} - \text{RTSPP}_{p})$$

$$\text{EBPWAPR}_{q, r, p} = \sum_{y} (\text{EBPPR}_{q, r, p, y} * \text{EBP}_{q, r, p, y} * \text{TLMP}_{y}) \Big/ \sum_{y} (\text{EBP}_{q, r, p, y} * \text{TLMP}_{y})$$

$$\text{EMRE}_{q, r, p} = \text{Max}\ (0, \text{Min}\ (\text{AEBP}_{q, r, p}, \text{RTMG}_{q, r, p}) - \tfrac{1}{4} * \text{BP}_{q, r, p})$$

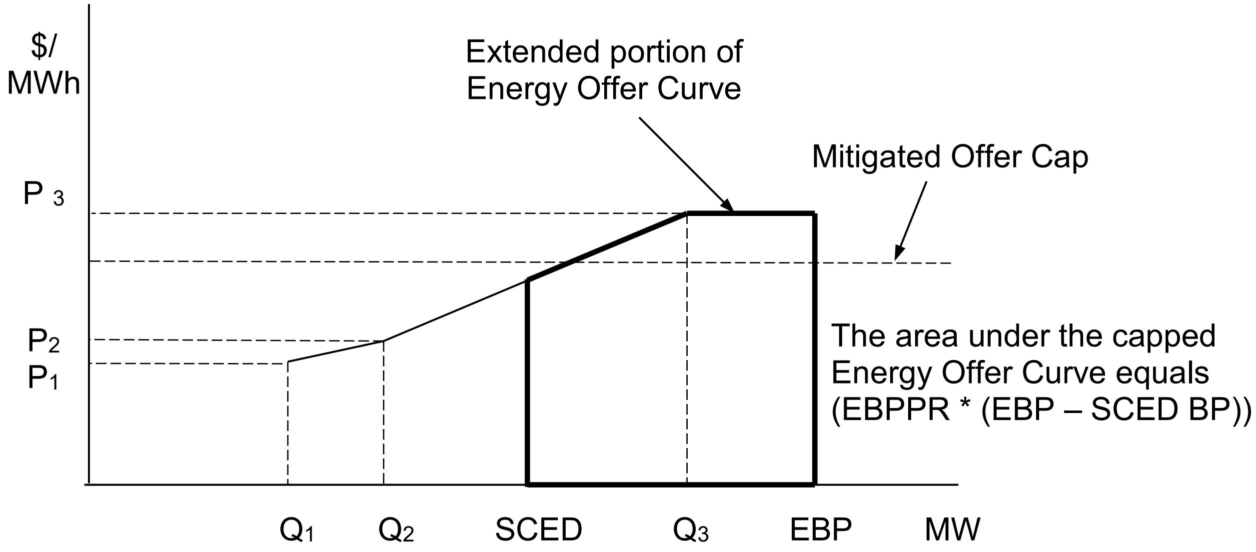
$$\text{AEBP}_{q, r, p} = \sum_{y} (\text{EBP}_{q, r, p, y} * \text{TLMP}_{y} / 3600)$$

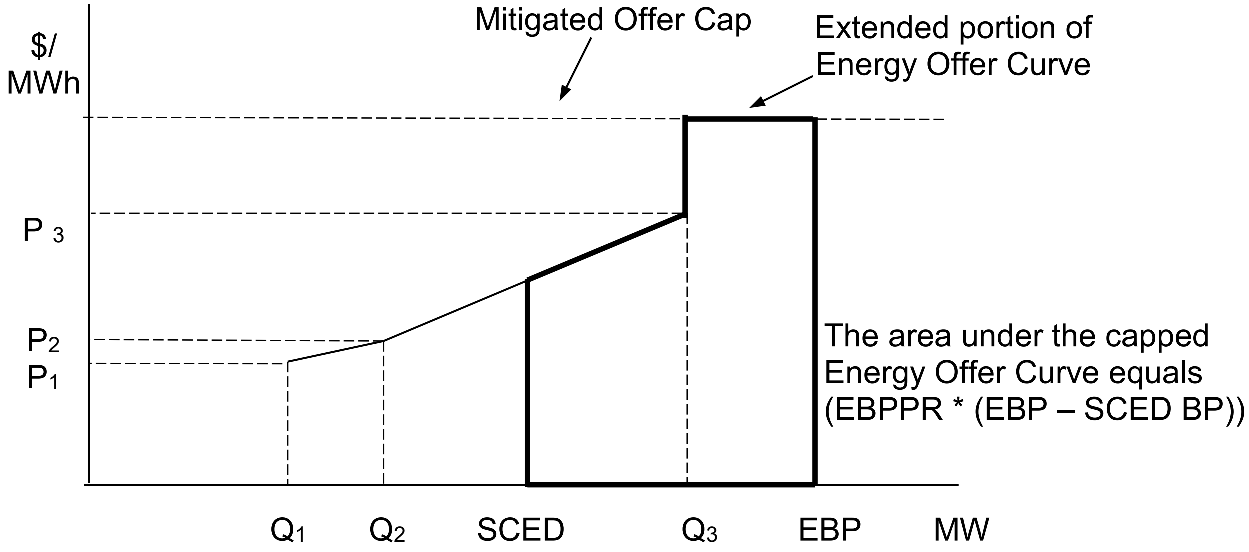
The above variables are defined as follows:

Variable	Unit	Definition
EMREAMT $_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMREPR $_{q, r, p}$	$/MWh	*Emergency Energy Price per QSE per Settlement Point per Resource*—The compensation rate for the additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMRE $_{q, r, p}$	MWh	*Emergency Energy per QSE per Settlement Point per Resource*—The additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EBPWAPR $_{q, r, p}$	$/MWh	*Emergency Base Point Weighted Average Price per QSE per Settlement Point per Resource*—The weighted average of the energy prices corresponding with the Emergency Base Points on the Energy Offer Curve for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
BP $_{q, r, p}$	MW	*Base Point per QSE per Settlement Point per Resource*—The Base Point of Resource *r* at Resource Node *p* represented by QSE *q* from the SCED prior to the Emergency Condition or Watch. For a Combined Cycle Train, the Resource *r* must be one of the registered Combined Cycle Generation Resources within the Combined Cycle Train.
AEBP $_{q, r, p}$	MWh	*Aggregated Emergency Base Point*—The Generation Resource's aggregated Emergency Base Point, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, AEBP is calculated for the Combined Cycle Train considering all emergency Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train.
EBP $_{q, r, p, y}$	MW	*Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
EBPPR $_{q, r, p, y}$	$/MWh	*Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The average incremental energy cost calculated per the Energy Offer Curve, capped by the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap, for the output levels between the SCED Base Point immediately before the Emergency Condition or Watch and the Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.

Variable	Unit	Definition
RTMG $_{q, r, p}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
TLMP $_y$	second	*Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource.
y	none	An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval.
3600	none	The number of seconds in one hour.

(2) The extension of the Energy Offer Curve is used to calculate the Emergency Base Point Price. If the Emergency Base Point MW value is greater than the largest MW value on the Energy Offer Curve submitted by the QSE for the Resource, then the Energy Offer Curve is extended to the Emergency Base Point MW value with a $/MWh value that is the MOC (pursuant to Section 4.4.9.4.1) for the highest MW output on the Energy Offer Curve submitted by the QSE for the Resource.





(3) The total additional compensation to each QSE for emergency power increases of Generation Resources for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{EMREAMTQSETOT}_{q} = \sum_{r} \sum_{p} \textbf{EMREAMT}_{q,r,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
EMREAMTQSETOT $_{q}$	$	*Emergency Energy Amount QSE Total per QSE*—The total of the payments to QSE *q* as additional compensation for emergency power increases of the Generation Resources represented by this QSE for the 15-minute Settlement Interval.
EMREAMT $_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource.

[NPRR1010 and NPRR1014: Replace applicable portions of Section 6.6.9.1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]

6.6.9.1 Payment for Emergency Operations Settlement

(1) ERCOT shall pay the QSE additional compensation for the Resource at its Resource Node Settlement Point during the Settlement Intervals that qualify for emergency Settlement as described in Section 6.6.9, Emergency Operations Settlement. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{EMREAMT}_{q,r,p} = \mathbf{(-1) * (EMREPRGEN}_{q,r,p} \mathbf{* EMREGEN}_{q,r,p}\mathbf{)} \mathbf{+ EMREPRLOAD}_{q,r,p} \mathbf{* EMRELOAD}_{q,r,p}$$

Where:

If any EBP > 0 then:

$$\text{EMREPRGEN}_{q,r,p} = \text{Max}\ (0, \text{EBPWAPRGEN}_{q,r,p} - \text{RTSPP}_{p})$$

$$\text{EBPWAPRGEN}_{q,r,p} = \sum_{y} (\text{EBPPR}_{q,r,p,y} * \text{Max}\ (0.001, \text{EBP}_{q,r,p,y}) * \text{TLMP}_{y}) \;/\; \sum_{y} (\text{Max}\ (0.001, \text{EBP}_{q,r,p,y}) * \text{TLMP}_{y})$$

$$\text{EMREGEN}_{q,r,p} = \text{Max}\ (0, \text{Min}\ (\text{AEBPGEN}_{q,r,p}, \text{RTMG}_{q,r,p}) - 1/4 * \text{Max}\ (0, \text{BP}_{q,r,p}))$$

$$\text{AEBPGEN}_{q,r,p} = \sum_{y} (\text{Max}\ (0, \text{EBP}_{q,r,p,y}) * \text{TLMP}_{y} / 3600)$$

If any EBP < 0 then:

$$\text{EMREPRLOAD}_{q,r,p} = \text{Max}\ (0, \text{RTSPP}_{p} - \text{EBPWAPRLOAD}_{q,r,p})$$

$$\text{EBPWAPRLOAD}_{q,r,p} = \sum_{y} (\text{EBPPR}_{q,r,p,y} * \text{Min}\ (-0.001, \text{EBP}_{q,r,p,y}) * \text{TLMP}_{y}) \;/\; \sum_{y} (\text{Min}\ (-0.001, \text{EBP}_{q,r,p,y}) * \text{TLMP}_{y})$$

$$\text{EMRELOAD}_{q,r,p} = \text{Min}\ (0, \text{Max}\ (\text{AEBPLOAD}_{q,r,p}, \text{RTCL}_{q,r,p}) - 1/4 * \text{Min}\ (0, \text{BP}_{q,r,p}))$$

$$\text{AEBPLOAD}_{q,r,p} = \sum_{y} (\text{Min}\ (0, \text{EBP}_{q,r,p,y}) * \text{TLMP}_{y} / 3600)$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
EMREAMT $_{q,\ r,\ p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMREPRGEN $_{q,\ r,\ p}$	$/MWh	*Emergency Energy Price for Generation per QSE per Settlement Point per Resource*—The compensation rate for the generation produced by Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMREPRLOAD $_{q,\ r,\ p}$	$/MWh	*Emergency Energy Price for Charging Load per QSE per Settlement Point per Resource*—The compensation rate for the charging load for Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMREGEN $_{q,\ r,\ p}$	MWh	*Emergency Energy for Generation per QSE per Settlement Point per Resource*—The generation produced by Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMRELOAD $_{q,\ r,\ p}$	MWh	*Emergency Energy for Charging Load per QSE per Settlement Point per Resource*—The charging load for Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EBPWAPRGEN $_{q,\ r,\ p}$	$/MWh	*Emergency Base Point Weighted Average Price for Generation per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the positive Emergency Base Points, for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EBPWAPRLOAD $_{q,\ r,\ p}$	$/MWh	*Emergency Base Point Weighted Average Price for Charging Load per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the negative Emergency Base Points, for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
BP $_{q,\ r,\ p}$	MW	*Base Point per QSE per Settlement Point per Resource*—The Base Point of Resource *r* at Resource Node *p* represented by QSE *q* from the SCED prior to the Emergency Condition or Watch. For a Combined Cycle Train, the Resource *r* must be one of the registered Combined Cycle Generation Resources within the Combined Cycle Train.
AEBPGEN $_{q,\ r,\ p}$	MWh	*Aggregated Emergency Base Point for Generation*—The aggregation of the positive Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, AEBP is calculated for the Combined Cycle Train considering all emergency Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train.

$\text{AEBPLOAD}_{q, r, p}$	MWh	*Aggregated Emergency Base Point for Charging Load*—The aggregation of the negative Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval.
$\text{EBP}_{q, r, p, y}$	MW	*Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{EBPPR}_{q, r, p, y}$	\$/MWh	*Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The average incremental energy cost calculated per the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the Emergency Base Point for Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. The Energy Offer Curve shall be capped by the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap and the Energy Bid/Offer Curve shall be capped by the maximum RTSPP at the Settlement Point for the Operating Day, per paragraph (10)(b) of Section 6.6.9. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTSPP_{p}	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
$\text{RTMG}_{q, r, p}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTCL}_{q, r, p}$	MWh	*Real-Time Charging Load per QSE per Resource per Settlement Point* —The charging load for Resource *r* at Resource Node *p* represented by the QSE *q*, represented as a negative value, for the 15-minute Settlement Interval.
TLMP_{y}	second	*Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource or ESR.
y	none	An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval.
3600	none	The number of seconds in one hour.

(2) ERCOT shall pay the QSE additional compensation for the Resource at its Resource Node Settlement Point during the Settlement Intervals that qualify for emergency Settlement as described in Section 6.6.9, Emergency Operations Settlement. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{EMREAMT}_{q, r, p} = \mathbf{Min}\ (\mathbf{0}, \mathbf{RTENET}_{q, r, p} + \mathbf{RTASNET}_{q, r, p})$$

(a) Where the Real-Time Energy Net Revenue is calculated as follows:

$RTENET_{q, r, p} = RTEREV_{q, r, p} - RTEREVT_{q, r, p}$

Where:

$RTEREV_{q, r, p} = RTSPP_{q, r, p} * (EMREGEN_{q, r, p} + EMRELOAD_{q, r, p})$

$RTEREVT_{q, r, p} = EBPWAPRGEN_{q, r, p} * EMREGEN_{q, r, p} + EBPWAPRLOAD_{q, r, p} * EMRELOAD_{q, r, p}$

If any EBP > 0 then:

$EBPWAPRGEN_{q, r, p} = \sum_{y} (EBPPR_{q, r, p, y} * \text{Max}(0.001, EBP_{q, r, p, y})* TLMP_{y}) / \sum_{y} (\text{Max}(0.001, EBP_{q, r, p, y}) * TLMP_{y})$

$EMREGEN_{q, r, p} = \text{Max}(0, \text{Min}(AEBPGEN_{q, r, p}, RTMG_{q, r, p}))$

$AEBPGEN_{q, r, p} = \sum_{y} (\text{Max}(0, EBP_{q, r, p, y}) * TLMP_{y} / 3600)$

If any EBP < 0 then:

$EBPWAPRLOAD_{q, r, p} = \sum_{y} (EBPPR_{q, r, p, y} * \text{Min}(-0.001, EBP_{q, r, p, y}) * TLMP_{y}) / \sum_{y} (\text{Min}(-0.001, EBP_{q, r, p, y}) * TLMP_{y})$

$EMRELOAD_{q, r, p} = \text{Min}(0, \text{Max}(AEBPLOAD_{q, r, p}, RTCL_{q, r, p}))$

$AEBPLOAD_{q, r, p} = \sum_{y} (\text{Min}(0, EBP_{q, r, p, y}) * TLMP_{y} / 3600)$

(b) Where the Real-Time Ancillary Services Net Revenue is calculated as follows:

$RTASNET_{q, r} = RTRUNET_{q, r} + RTRDNET_{q, r} + RTNSNET_{q, r} + RTRRNET_{q, r} + RTECRNET_{q, r}$

Where for Reg-Up:

$RTRUNET_{q, r} = RTRUREV_{q, r} - (¼)* RTRUREVT_{q, r, p}$

$RTRUREVT_{q, r, p} = RTRUWAPR_{q, r, p} * RTRUAWD_{q, r}$

$$\text{RTRUWAPR}_{q,\,r,\,p} = \sum_{y} (\text{RTRUOPR}_{q,\,r,\,p,\,y} * \text{Max}\ (0.001, \text{RTRUAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})\ / \sum_{y} (\text{Max}\ (0.001, \text{RTRUAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})$$

Where for Reg-Down:

$$\text{RTRDNET}_{q,\,r} = \text{RTRDREV}_{q,\,r} - (\tfrac{1}{4}) * \text{RTRDREVT}_{q,\,r,\,p}$$

$$\text{RTRDREVT}_{q,\,r,\,p} = \text{RTRDWAPR}_{q,\,r,\,p} * \text{RTRDAWD}_{q,\,r}$$

$$\text{RTRDWAPR}_{q,\,r,\,p} = \sum_{y} (\text{RTRDOPR}_{q,\,r,\,p,\,y} * \text{Max}\ (0.001, \text{RTRDAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})\ / \sum_{y} (\text{Max}\ (0.001, \text{RTRDAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})$$

Where for RRS:

$$\text{RTRRNET}_{q,\,r} = \text{RTRRREV}_{q,\,r} - (\tfrac{1}{4}) * \text{RTRRREVT}_{q,\,r,\,p}$$

$$\text{RTRRREVT}_{q,\,r,\,p} = \text{RTRRWAPR}_{q,\,r,\,p} * \text{RTRRAWD}_{q,\,r}$$

$$\text{RTRRWAPR}_{q,\,r,\,p} = \sum_{y} (\text{RTRROPR}_{q,\,r,\,p,\,y} * \text{Max}\ (0.001, \text{RTRRAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})\ / \sum_{y} (\text{Max}\ (0.001, \text{RTRRAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})$$

Where for Non-Spin:

$$\text{RTNSNET}_{q,\,r} = \text{RTNSREV}_{q,\,r} - (\tfrac{1}{4}) * \text{RTNSREVT}_{q,\,r,\,p}$$

$$\text{RTNSREVT}_{q,\,r,\,p} = \text{RTNSWAPR}_{q,\,r,\,p} * \text{RTNSAWD}_{q,\,r}$$

$$\text{RTNSWAPR}_{q,\,r,\,p} = \sum_{y} (\text{RTNSOPR}_{q,\,r,\,p,\,y} * \text{Max}\ (0.001, \text{RTNSAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})\ / \sum_{y} (\text{Max}\ (0.001, \text{RTNSAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y})$$

Where for ERCOT Contingency Reserve (ECRS):

$$\text{RTECRNET}_{q,\,r} = \text{RTECRREV}_{q,\,r} - (\tfrac{1}{4}) * \text{RTECRREVT}_{q,\,r}$$

$$\text{RTECRREVT}_{q,\,r,\,p} = \text{RTECRWAPR}_{q,\,r,\,p} * \text{RTECRAWD}_{q,\,r}$$

$$\text{RTECRWAPR}_{q,r,p} = \sum_{y} (\text{RTECROPR}_{q,r,p,y} * \text{Max}(0.001, \text{RTECRAWDS}_{q,r,p,y}) * \text{TLMP}_{y}) / \sum_{y} (\text{Max}(0.001, \text{RTECRAWDS}_{q,r,p,y}) * \text{TLMP}_{y})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
EMREAMT $_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTENET $_{q, r, p}$	$	*Real-Time Energy Net Revenue*– The net difference between the Real-Time Energy Revenue and the Real-Time Energy Revenue Target for QSE *q* for Resource *r* at Resource node *p* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTASNET $_{q, r,}$	$	*Real-Time Ancillary Service Net Revenue* – The sum of the Ancillary Service net revenues for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTEREV $_{q, r, p}$	$	*Real-Time Energy Revenue*— The calculated Real-Time energy revenue at the RTSPP for QSE *q* calculated for Resource *r* at Resource node *p* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMREGEN $_{q, r, p}$	MWh	*Emergency Energy for Generation per QSE per Settlement Point per Resource*—The generation produced by Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EMRELOAD $_{q, r, p}$	MWh	*Emergency Energy for Charging Load per QSE per Settlement Point per Resource*—The charging load for Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTEREVT $_{q, r, p}$	$	*Real-Time Energy Revenue Target* – The energy revenue target at the EBPWAPRGEN and EBPWAPRLOAD of the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EBPWAPRGEN $_{q, r, p}$	$/MWh	*Emergency Base Point Weighted Average Price for Generation per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the positive Emergency Base Points for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
EBPWAPRLOAD $_{q, r, p}$	$/MWh	*Emergency Base Point Weighted Average Price for Charging Load per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the negative Emergency Base Points, for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

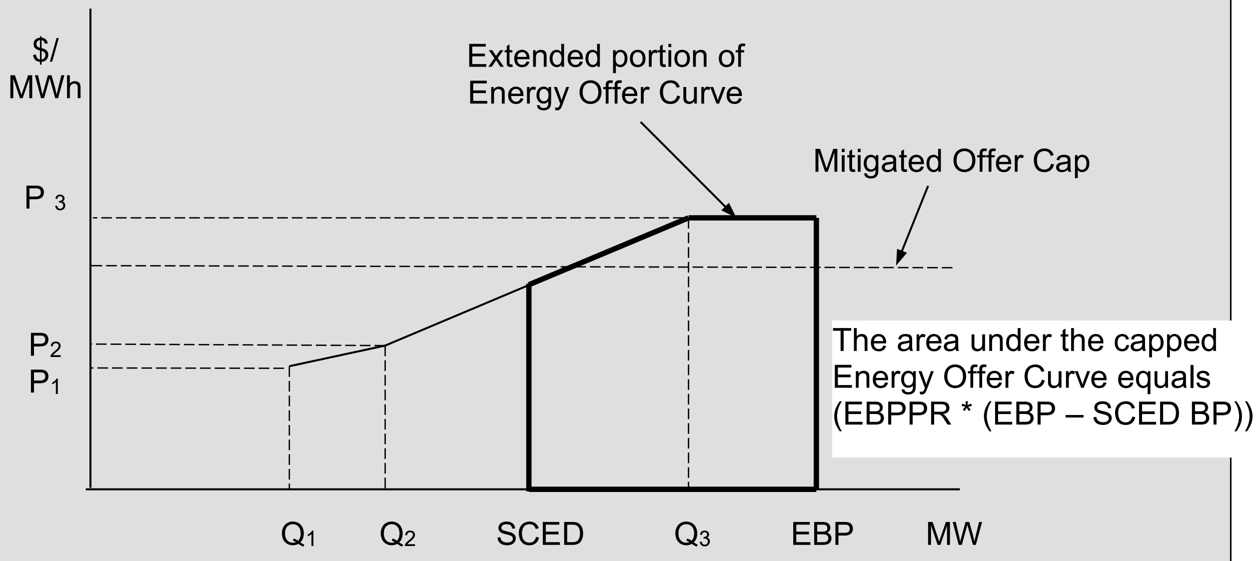
AEBPGEN $_{q, r, p}$	MWh	*Aggregated Emergency Base Point for Generation*—The aggregation of the positive Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, AEBP is calculated for the Combined Cycle Train considering all emergency Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train.
AEBPLOAD $_{q, r, p}$	MWh	*Aggregated Emergency Base Point for Charging Load*—The aggregation of the negative Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval.
EBP $_{q, r, p, y}$	MW	*Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
EBPPR $_{q, r, p, y}$	$/MWh	*Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The average incremental energy cost calculated per the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the Emergency Base Point for Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. The Energy Offer Curve shall be capped by the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap, and the Energy Bid/Offer Curve shall be capped by the maximum RTSPP at the Settlement Point for the Operating Day, per paragraph (10)(b) of Section 6.6.9. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
RTMG $_{q, r, p}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTCL $_{q, r, p}$	MWh	*Real-Time Charging Load per QSE per Resource per Settlement Point* —The charging load for Resource *r* at Resource Node *p* represented by the QSE *q,* represented as a negative value, for the 15-minute Settlement Interval.
RTRUNET $_{q, r}$	$	*Real-Time Reg-Up Net Revenue*– The difference between the Real-Time Reg-Up Revenue and the Real-Time Reg-Up Revenue Target for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDNET $_{q, r}$	$	*Real-Time Reg-Down Net Revenue* – The difference between calculated revenue for the Real-Time Reg-Down Revenue and the Real-Time Reg-Down Revenue Target for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRRNET $_{q, r}$	$	*Real-Time Responsive Reserve Net Revenue* – The difference between Real-Time RRS Revenue and the Real-Time RRS Revenue Target for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

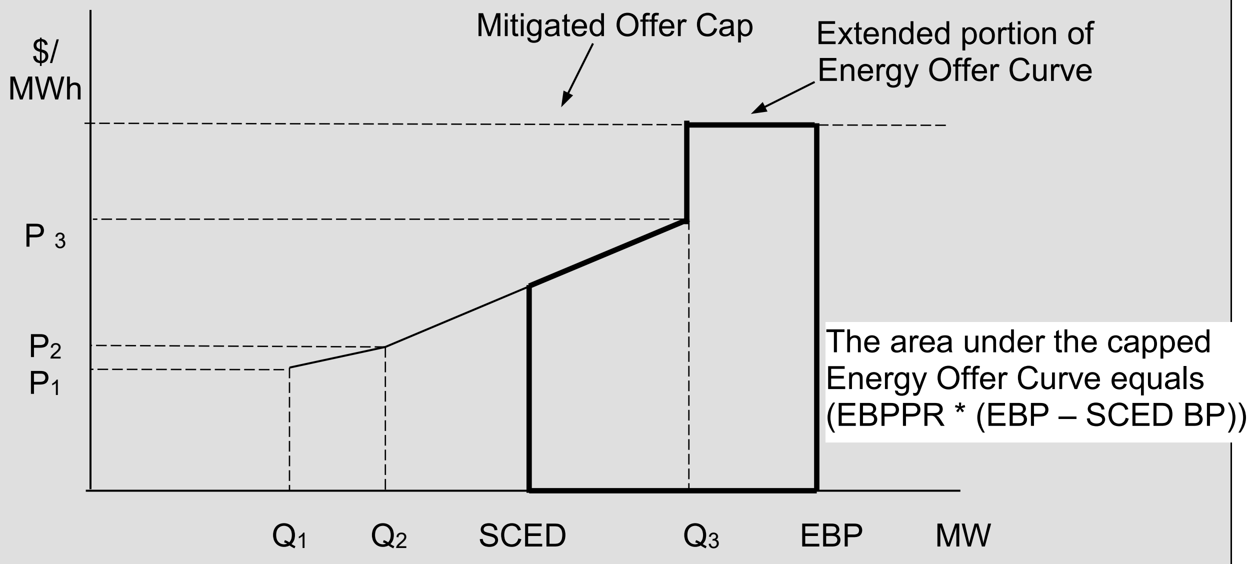
$RTNSNET_{q,\,r}$	$	*Real-Time Non-Spin Net Revenue* – The difference between Real-Time Non-Spin Revenue and the Real-Time Non-Spin Revenue Target for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTECRNET_{q,\,r}$	$	*Real-Time ERCOT Contingency Reserve Service Net Revenue* – The difference between Real-Time ECRS Revenue and the Real-Time ECRS Revenue Target for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTUREV_{q,\,r}$	$	*Real-Time Reg-Up Revenue*— The calculated Real-Time Reg-Up revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTRDREV_{q,\,r}$	$	*Real-Time Reg-Down Revenue*— The calculated Real-Time Reg-Down revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTRRREV_{q,\,r}$	$	*Real-Time Responsive Reserve Revenue*— The calculated Real-Time RRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTNSREV_{q,\,r}$	$	*Real-Time Non-Spin Revenue*— The calculated Real-Time Non-Spin revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTECRREV_{q,\,r}$	$	*Real-Time ERCOT Contingency Reserve Service Revenue*— The calculated Real-Time ECRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTUREVT_{q,\,r}$	$	*Real-Time Reg-Up Revenue Target* – The revenue target of the Reg-Up award to Resource *r* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTRDREVT_{q,\,r}$	$	*Real-Time Reg-Down Revenue Target* – The revenue target of the Reg-Down award to Resource *r* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTRRREVT_{q,\,r}$	$	*Real-Time Responsive Reserve Revenue Target* – The revenue target of the RRS award to Resource *r* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTNSREVT_{q,\,r}$	$	*Real-Time Non-Spin Revenue Target* – The revenue target of the Non-Spin award to Resource *r* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTECRREVT_{q,\,r}$	$	*Real-Time ERCOT Contingency Reserve Service Revenue Target* – The revenue target of the ECRS award to Resource *r* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

RTRUWAPR $_{q, r, p}$	$/MW	*Real-Time Reg-Up Weighted-Average Price* – The weighted average of the Ancillary Service Offer prices corresponding with the Reg-Up awards on the Ancillary Service Offer curves for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDWAPR $_{q, r, p}$	$/MW	*Real-Time Reg-Down Weighted-Average Price* – The weighted average of the Ancillary Service Offer prices corresponding with the Reg-Down awards on the Ancillary Service Offer curves for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRRWAPR $_{q, r, p}$	$/MW	*Real-Time Responsive Reserve Weighted-Average Price* – The weighted average of the Ancillary Service Offer prices corresponding with the RRS awards on the Ancillary Service Offer curves for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTNSWAPR $_{q, r, p}$	$/MW	*Real-Time Non-Spin Weighted-Average Price* – The weighted average of the Ancillary Service Offer prices corresponding with the Non-Spin awards on the Ancillary Service Offer curves for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTECRWAPR $_{q, r, p}$	$/MW	*Real-Time ERCOT Contingency Reserve Service Weighted-Average Price* – The weighted average of the Ancillary Service Offer prices corresponding with the ECRS awards on the Ancillary Service Offer curves for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRUAWD $_{q, r}$	MW	*Real-Time Reg-Up Award per Resource per QSE*— The Reg-Up amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDAWD $_{q, r}$	MW	*Real-Time Reg-Down Award per Resource per QSE*— The Reg-Down amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRRAWD $_{q, r}$	MW	*Real-Time Responsive Reserve Award per Resource per QSE*— The RRS amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTNSAWD $_{q, r}$	MW	*Real-Time Non-Spin Award per Resource per QSE*— The Non-Spin amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTECRAWD $_{q, r}$	MW	*Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE*— The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRUOPR $_{q, r, p, y}$	$/MW	*Real-Time Reg-Up Offer Price* – The price on the Ancillary Service Offer curve at the Reg-Up award of Resource *r* at Resource Node *p* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

$\text{RTRDOPR}_{q, r, p, y}$	\$/MW	*Real-Time Reg-Down Offer Price* – The price on the Ancillary Service Offer curve at the Reg-Down award of Resource *r* at Resource Node *p* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTRROPR}_{q, r, p, y}$	\$/MW	*Real-Time Responsive Reserve Offer Price* – The price on the Ancillary Service Offer curve at the RRS award of Resource *r* at Resource Node *p* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTNSOPR}_{q, r, p, y}$	\$/MW	*Real-Time Non-Spin Offer Price* – The price on the Ancillary Service Offer curve at the Non-Spin award of Resource *r* at Resource Node *p* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTECROPR}_{q, r, p, y}$	\$/MW	*Real-Time ERCOT Contingency Reserve Service Offer Price* – The price on the Ancillary Service Offer curve at the ECRS award of Resource *r* at Resource Node *p* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTRUAWDS}_{q, r, p, y}$	MW	*Real-Time Reg-Up Award per Resource per QSE per SCED interval* - The Reg-Up amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTRDAWDS}_{q, r, p, y}$	MW	*Real-Time Reg-Down Award per Resource per QSE per SCED interval* - The Reg-Down amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTRRAWDS}_{q, r, p, y}$	MW	*Real-Time Responsive Reserve Award per Resource per QSE per SCED interval* - The RRS amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTNSAWDS}_{q, r, p, y}$	MW	*Real-Time Non-Spin Award per Resource per QSE per SCED interval* - The Non-Spin amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTECRAWDS}_{q, r, p, y}$	MW	*Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE per SCED interval* - The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
TLMP_{y}	second	*Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource or ESR.
y	none	An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval.
3600	none	The number of seconds in one hour.

(3) The extension of the Energy Offer Curve or Energy Bid/Offer Curve is used to calculate the Emergency Base Point Price. If the Emergency Base Point MW value is greater than the largest MW value on the Energy Offer Curve or Energy Bid/Offer Curve submitted by the QSE for the Resource, then the Energy Offer Curve or Energy Bid/Offer Curve is extended to the Emergency Base Point MW value with a $/MWh value that is the MOC (pursuant to Section 4.4.9.4.1) for the highest MW output on the Energy Offer Curve or Energy Bid/Offer Curve submitted by the QSE for the Resource.





(4) The total additional compensation to each QSE for emergency Settlement of Resources for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{EMREAMTQSETOT}_{q} = \sum_{r} \sum_{p} \textbf{EMREAMT}_{q, r, p}$$

The above variables are defined as follows:

Variable	Unit	Definition
EMREAMTQSETOT $_{q}$	$	*Emergency Energy Amount QSE Total per QSE*—The total of the payments to QSE *q* as additional compensation for additional energy or Ancillary Services of the Resources represented by this QSE for the 15-minute Settlement Interval.
EMREAMT $_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource or ESR.

6.6.9.2 Charge for Emergency Power Increases

(1) The total cost for additional compensation for emergency power increases and unannounced Generation Resource tests is allocated to the QSEs representing Loads based on LRS. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{LAEMREAMT}_{q} = (-1) * \textbf{EMREAMTTOT} * \textbf{LRS}_{q}$$

Where:

$$\text{EMREAMTTOT} = \sum_{q} \text{EMREAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LAEMREAMT $_{q}$	$	*Load-Allocated Emergency Energy Amount per QSE*—The QSE *q*'s Load-allocated amount of the total payments for all the Generation Resources with Real-Time Emergency Base Points, for the 15-minute Settlement Interval.

Variable	Unit	Definition
EMREAMTTOT	$	*Emergency Energy Amount Total*—The total of the payments to all QSEs as additional compensation for emergency power increases of the Generation Resources for the 15-minute Settlement Interval.
EMREAMTQSETOT $_q$	$	*Emergency Energy Amount QSE Total per QSE*—The total of the payments to QSE *q* as additional compensation for emergency power increases of the Generation Resources represented by this QSE for the 15-minute Settlement Interval.
LRS $_q$	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.

[NPRR1010 and NPRR1014: Replace applicable portions of Section 6.6.9.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]

6.6.9.2 Charge for Emergency Operations Settlement

(1) The total cost for additional compensation for emergency Settlement as calculated in Section 6.6.9.1, Payment for Emergency Operations Settlement, is allocated to the QSEs representing Loads based on LRS. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LAEMREAMT}_{q} = \mathbf{(-1) * EMREAMTTOT * LRS}_{q}$$

Where:

$$\text{EMREAMTTOT} = \sum_{q} \text{EMREAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LAEMREAMT $_q$	$	*Load-Allocated Emergency Energy Amount per QSE*—The QSE *q*'s Load-allocated amount of the total payments for all the Resources with Real-Time Emergency Base Points, for the 15-minute Settlement Interval.
EMREAMTTOT	$	*Emergency Energy Amount Total*—The total of the payments to all QSEs as additional compensation for additional energy or Ancillary Services of the Resources for the 15-minute Settlement Interval.
EMREAMTQSETOT $_q$	$	*Emergency Energy Amount QSE Total per QSE*—The total of the payments to QSE *q* as additional compensation for additional energy or Ancillary Services of the Resources represented by this QSE for the 15-minute Settlement Interval.
LRS $_q$	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.

6.6.10 Real-Time Revenue Neutrality Allocation

(1) ERCOT must be revenue-neutral in each Settlement Interval. Each QSE receives an allocated share, on a LRS basis, of the net amount of:

(a) Real-Time Energy Imbalance payments or charges under Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(b) Real-Time Energy Imbalance payments or charges under Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

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

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

(e) Real-Time energy payments under Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(f) Real-Time Energy payments or charges under Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG);

[NPRR995: Replace item (f) above with the following upon system implementation:]

(f) Real-Time Energy payments or charges under Section 6.6.3.9, 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);

(g) Real-Time congestion payments or charges under Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules; and

(h) Real-Time payments or charges to the Congestion Revenue Right (CRR) Owners under Section 7.9.2, Real-Time CRR Payments and Charges.

(2) The Real-Time Revenue Neutrality Allocation for each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LARTRNAMT}_{q} = \mathbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTESOGAMTTOT + RTCCAMTTOT + RTOBLAMTTOT / 4 + RTOBLLOAMTTOT / 4) * LRS}_{q}$$

[NPRR995: Replace the formula "LARTRNAMT $_q$" above with the following upon system implementation:]

$$\textbf{LARTRNAMT}_q = \textbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTESOAMTTOT + RTCCAMTTOT + RTOBLAMTTOT / 4 + RTOBLLOAMTTOT / 4) * LRS}_q$$

Where:

Total Real-Time Energy Imbalance Payment (or Charge) at Settlement Point (or Hub)

$$\text{RTEIAMTTOT} = \sum_q \text{RTEIAMTQSETOT}_q$$

Total Real-Time Payment for BLT Resources

$$\text{BLTRAMTTOT} = \sum_q \text{BLTRAMTQSETOT}_q$$

Total Real-Time Payment for DC Tie Imports

$$\text{RTDCIMPAMTTOT} = \sum_q \text{RTDCIMPAMTQSETOT}_q$$

Total Real-Time Congestion Payment or Charge for Self-Schedules

$$\text{RTCCAMTTOT} = \sum_q \text{RTCCAMTQSETOT}_q$$

Total Real-Time Payment or Charge for Point-to-Point (PTP) Obligations

$$\text{RTOBLAMTTOT} = \sum_q \text{RTOBLAMTQSETOT}_q$$

Total Real-Time Payment for PTP Obligations with Links to Options

$$\text{RTOBLLOAMTTOT} = \sum_q \text{RTOBLLOAMTQSETOT}_q$$

Total Real-Time Payment or Charge for energy from SODGs and SOTGs

$$\text{RTESOGAMTTOT} = \sum_q \text{RTESOGAMTQSETOT}_q$$

[NPRR995: Replace the language above with the following upon system implementation:]

Total Real-Time Payment or Charge for energy from SODGs, SOTGs, SODESSs, or SOTESSs

$$\text{RTESOAMTTOT} = \sum_q \text{RTESOAMTQSETOT}_q$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTRNAMT $_q$	$	*Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*'s share of the total Real-Time revenue neutrality amount, for the 15-minute Settlement Interval.
RTEIAMTTOT $_q$	$	*Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance Service at all Settlement Points (Resource, Load Zone or Hub) for the 15-minute Interval.
BLTRAMTTOT	$	*Block Load Transfer Resource Amount Total*—The total of payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTTOT	$	*Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval.
RTCCAMTTOT	$	*Real-Time Energy Congestion Cost Amount Total*—The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval.
RTOBLAMTTOT	$	*Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval.
RTOBLLOAMTTOT	$	*Real-Time Obligation with Links to an Option Amount Total*—The sum of all payments for PTP Obligations with Links to an Option settled in Real-Time for the hour that includes the 15-minute Settlement Interval.
RTEIAMTQSETOT $_q$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance at all Resource Node Settlement Points for the 15-minute Settlement Interval.
RTCCAMTQSETOT $_q$	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
BLTRAMTQSETOT $_q$	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTQSETOT $_q$	$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
RTOBLAMTQSETOT $_q$	$	*Real-Time Obligation Amount QSE Total per QSE*—The net total payment or charge to QSE *q* of all its PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time.
RTOBLLOAMTQSETOT $_q$	$	*Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The total payment to QSE *q* for all of its PTP Obligations with Links to an Option settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.1.
RTESOGAMTQSETOT $_q$	$	*Real-Time Energy Payment or Charge per QSE for Energy from SODGs and SOTGs* —The payment or charge to QSE *q* for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval.
RTESOGAMTTOT	$	*Real-Time Energy Amount Total for Energy from all SODGs and SOTGs* —The total net payments and charges to all QSEs for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval.

Variable	Unit	Description
[NPRR995: Replace the variables "RTESOGAMTQSETOT $_q$" and "RTESOGAMTTOT" above with the following upon system implementation:]		
RTESOAMTQSETOT $_q$	$	*Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESSs, or SOTESSs* —The payment or charge to QSE *q* for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs, for the 15-minute Settlement Interval.
RTESOAMTTOT	$	*Real-Time Energy Amount Total from all SODGs, SOTGs, SODESSs, or SOTESSs* —The total net payments and charges to all QSEs for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs, for the 15-minute Settlement Interval.
LRS $_q$	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
o	none	A CRR owner.

(3) In the event that ERCOT is unable to execute the DAM, the Real-Time Revenue Neutrality Allocation for each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LARTRNAMT}_{q} = \mathbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTESOGAMTTOT + RTCCAMTTOT + NDRTOBLAMTTOT / 4 + NDRTOPTAMTTOT / 4 + NDRTOPTRAMTTOT / 4 + NDRTOBLRAMTTOT / 4) * LRS}_{q}$$

[NPRR995: Replace the formula "LARTRNAMT $_q$" above with the following upon system implementation:]

$$\mathbf{LARTRNAMT}_{q} = \mathbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTESOAMTTOT + RTCCAMTTOT + NDRTOBLAMTTOT / 4 + NDRTOPTAMTTOT / 4 + NDRTOPTRAMTTOT / 4 + NDRTOBLRAMTTOT / 4) * LRS}_{q}$$

Where:

Total Real-Time Energy Imbalance Payment (or Charge) at Settlement Point (or Hub)

$$\text{RTEIAMTTOT} = \sum_{q} \text{RTEIAMTQSETOT}_{q}$$

Total Real-Time Payment for BLT Resources

$$\text{BLTRAMTTOT} = \sum_{q} \text{BLTRAMTQSETOT}_{q}$$

Total Real-Time Payment for DC Tie Imports

$$\text{RTDCIMPAMTTOT} = \sum_{q} \text{RTDCIMPAMTQSETOT}_{q}$$

Total Real-Time Congestion Payment or Charge for Self Schedules

$$\text{RTCCAMTTOT} = \sum_{q} \text{RTCCAMTQSETOT}_{q}$$

Total Real-Time Payment or Charge for PTP Obligations when ERCOT is unable to execute the DAM

$$\text{NDRTOBLAMTTOT} = \sum_{o} \text{NDRTOBLAMTOTOT}_{o}$$

Total Real-Time Payment for PTP Options when ERCOT is unable to execute the DAM

$$\text{NDRTOPTAMTTOT} = \sum_{o} \text{NDRTOPTAMTOTOT}_{o}$$

Total Real-Time Payment for PTP Options with Refund when ERCOT is unable to execute the DAM

$$\text{NDRTOPTRAMTTOT} = \sum_{o} \text{NDRTOPTRAMTOTOT}_{o}$$

Total Real-Time Payment or Charge for PTP Obligations with Refund when ERCOT is unable to execute the DAM

$$\text{NDRTOBLRAMTTOT} = \sum_{o} \text{NDRTOBLRAMTOTOT}_{o}$$

Total Real-Time Payment or Charge for energy from SODGs and SOTGs

$$\text{RTESOGAMTTOT} = \sum_{q} \text{RTESOGAMTQSETOT}_{q}$$

[NPRR995: Replace the language above with the following upon system implementation:]

Total Real-Time Payment or Charge for energy from SODGs, SOTGs, SODESSs, or SOTESSs

$$\text{RTESOAMTTOT} = \sum_{q} \text{RTESOAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTRNAMT_{q}	\$	*Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*'s share of the total Real-Time revenue neutrality amount for the 15-minute Settlement Interval.
RTEIAMTTOT	\$	*Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance at all Settlement Points (Resource, Load Zone, or Hub) for the 15-minute Interval.
BLTRAMTTOT	\$	*Block Load Transfer Resource Amount Total*—The total of the payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.

Variable	**Unit**	**Description**
RTDCIMPAMTTOT	$	*Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval.
RTCCAMTTOT	$	*Real-Time Energy Congestion Cost Amount Total*—The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval.
NDRTOBLAMTTOT	$	*No DAM Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOPTAMTTOT	$	*No DAM Real-Time Option Amount Total*—The sum of all payments for PTP Options settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOPTRAMTTOT	$	*No DAM Real-Time Option with Refund Amount Total*—The sum of all payments for PTP Options with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOBLRAMTTOT	$	*No DAM Real-Time Obligation with Refund Amount Total*—The sum of all payments for PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
$\mathrm{RTEIAMTQSETOT}_{q}$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval.
$\mathrm{RTCCAMTQSETOT}_{q}$	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
$\mathrm{BLTRAMTQSETOT}_{q}$	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
$\mathrm{RTDCIMPAMTQSETOT}_{q}$	$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
$\mathrm{NDRTOBLAMTOTOT}_{o}$	$	*No DAM Real-Time Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* of all its PTP Obligations settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\mathrm{NDRTOPTAMTOTOT}_{o}$	$	*No DAM Real-Time Option Amount Owner Total per CRR Owner*—The total payment to CRR owner *o* for all its PTP Options settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\mathrm{NDRTOPTRAMTOTOT}_{o}$	$	*No DAM Real-Time Option with Refund Amount Owner Total per CRR Owner*—The total payment to Non-Opt-In Entity (NOIE) CRR owner *o* for all its PTP Options with Refund settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\mathrm{NDRTOBLRAMTOTOT}_{o}$	$	*No DAM Real-Time Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* for all its PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.

Variable	Unit	Description
$\text{RTESOGAMTQSETOT}_{q}$	$	*Real-Time Energy Payment or Charge per QSE for Energy from SODGs and SOTGs* —The payment or charge to QSE *q* for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval.
RTESOGAMTTOT	$	*Real-Time Energy Amount Total for Energy from all SODGs and SOTGs* —The total net payments and charges to all QSEs for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval.

[NPRR995: Replace the variables "RTESOGAMTQSETOT $_{q}$" and "RTESOGAMTTOT" above with the following upon system implementation:]

$\text{RTESOAMTQSETOT}_{q}$	$	*Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESSs, or SOTESSs* —The payment or charge to QSE *q* for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs, for the 15-minute Settlement Interval.
RTESOAMTTOT	$	*Real-Time Energy Amount Total from all SODGs, SOTGs, SODESSs, or SOTESSs* —The total net payments and charges to all QSEs for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs, for the 15-minute Settlement Interval.

LRS_{q}	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2.
q	none	A QSE.
o	none	A CRR Owner.

6.6.11 Emergency Response Service Capacity

6.6.11.1 Emergency Response Service Capacity Payments

(1) ERCOT shall pay, for each Emergency Response Service (ERS) Contract Period, the QSEs representing ERS Resources as follows:

$$\mathbf{ERSPAMT}_{qc(tp)d} = \mathbf{COMPAMT}_{qc(tp)d} + \mathbf{SPAMT}_{qc(tp)d}$$

$$\mathbf{ERSPAMTQSETOT}_{qcd} = \sum_{tp} \mathbf{ERSPAMT}_{qc(tp)d}$$

$$\mathbf{ERSPAMTTOT}_{c(tp)d} = \sum_{q} \mathbf{ERSPAMT}_{qc(tp)d}$$

Where:

$$\text{COMPAMT}_{qc(tp)d} = -1 * \text{ERSPRICE}_{qc(tp)d} * \text{COMPDELQSEMW}_{qcd(tp)d} * \text{TPH}_{c(tp)d}$$

$$\text{SPAMT}_{qc(tp)d} = -1 * (\text{ERSPRICE}_{qc(tp)d} * (\text{Min}(\text{SPCUL}_{qc(tp)d}, \text{SPDELQSEMW}_{qc(tp)d}) * \text{TPH}_{c(tp)d})$$

$$\text{COMPDELQSEMW}_{qc(tp)d} = \sum_{e=1}^{co} \text{COMPDELMW}_{qce(tp)d}$$

$$\text{COMPDELMWTOT}_{c(tp)d} = \sum_{q=1}^{n} \text{COMPDELQSEMW}_{qc(tp)d}$$

$$\text{SPDELQSEMW}_{qc(tp)d} = \sum_{e=1}^{s} \text{SPDELMW}_{qce(tp)d}$$

$$\text{SPDELMWTOT}_{c(tp)d} = \sum_{q} \text{SPDELQSEMW}_{qc(tp)d}$$

$$\text{COMPDELMW}_{qce(tp)d} = \text{ERSTESTPF}_{qred} * \text{COMPOFFERMW}_{qce(tp)d} * (\text{ERSAFWT}_{qcd} * \text{Min}(\text{ERSAFCOMB}_{qrd},1) + (1 - \text{ERSAFWT}_{qcd}) * \text{Min}(\text{ERSEPF}_{qrd},1))$$

$$\text{SPDELMW}_{qc(tp)d} = \text{ERSTESTPF}_{qred} * \text{SPOFFERMW}_{qce(tp)d} * (\text{ERSAFWT}_{qcd} * \text{Min}(\text{ERSAFCOMB}_{qrd},1) + (1 - \text{ERSAFWT}_{qcd}) * \text{Min}(\text{ERSEPF}_{qrd},1))$$

The ERS Self-Provision Capacity Upper Limit for each self-providing QSE shall be calculated by ERCOT using a two-pass process for each of the four ERS service types. The first pass will consist of simultaneously solving for all QSEs' ERS Self-Provision Capacity Upper Limits with the constraint that each QSE's ERS Self-Provision Capacity Upper Limit will equal its LRS multiplied by the total capacity awarded for competitive offers, plus the sum of all QSEs' ERS Self-Provision Capacity Upper Limits. The second pass will repeat the solution of the equations with a QSE's delivered self-provided MW capacity (adjusted for availability and/or event performance) substituted for the ERS Self-Provision Capacity Upper Limit if the delivered MW capacity is less than the first pass calculation of the ERS Self-Provision Capacity Upper Limit.

Pass 1:

For QSE 1:

$$\mathbf{SPCUL}_{1c(tp)d} = \mathbf{ERSLRS}_{1c(tp)d} * (\mathbf{COMPDELMWTOT}_{c(tp)d} + \mathbf{SPCUL}_{1c(tp)d} + \mathbf{SPCUL}_{2c(tp)d} + \ldots + \mathbf{SPCUL}_{nc(tp)d})$$

For QSE 2:

$$\mathbf{SPCUL}_{2c(tp)d} = \mathbf{ERSLRS}_{2c(tp)d} * (\mathbf{COMPDELMWTOT}_{c(tp)d} + \mathbf{SPCUL}_{1c(tp)d} + \mathbf{SPCUL}_{2c(tp)d} + \ldots + \mathbf{SPCUL}_{nc(tp)d})$$

…

For QSE n:

$$\mathbf{SPCUL}_{nc(tp)d} = \mathbf{ERSLRS}_{nc(tp)d} * (\mathbf{COMPDELMWTOT}_{c(tp)d} + \mathbf{SPCUL}_{1c(tp)d} + \mathbf{SPCUL}_{2c(tp)d} + \ldots + \mathbf{SPCUL}_{nc(tp)d})$$

Pass 2:

For QSE 1:

$$\mathbf{SPCUL}_{1c(tp)d} = \mathbf{ERSLRS}_{1c(tp)d} * (\mathbf{COMPDELMWTOT}_{c(tp)d} + \mathbf{Min}(\mathbf{SPDELMW}_{1c(tp)d}, \mathbf{SPCUL}_{1c(tp)d}) + \mathbf{Min}(\mathbf{SPDELMW}_{2c(tp)d}, \mathbf{SPCUL}_{2c(tp)d}) + \ldots + \mathbf{Min}(\mathbf{SPDELMW}_{nc(tp)d}, \mathbf{SPCUL}_{nc(tp)d}))$$

For QSE 2:

$$\mathbf{SPCUL}_{2c(tp)d} = \mathbf{ERSLRS}_{2c(tp)d} * (\mathbf{COMPDELMWTOT}_{c(tp)d} + \mathbf{Min}(\mathbf{SPDELMW}_{1c(tp)d}, \mathbf{SPCUL}_{1c(tp)d}) + \mathbf{Min}(\mathbf{SPDELMW}_{2c(tp)d}, \mathbf{SPCUL}_{2c(tp)d}) + \ldots + \mathbf{Min}(\mathbf{SPDELMW}_{nc(tp)d}, \mathbf{SPCUL}_{nc(tp)d}))$$

…

For QSE n:

$$\mathbf{SPCUL}_{nc(tp)d} = \mathbf{ERSLRS}_{nc(tp)d} * (\mathbf{COMPDELMWTOT}_{c(tp)d} + \mathbf{Min}(\mathbf{SPDELMW}_{1c(tp)d}, \mathbf{SPCUL}_{1c(tp)d}) + \mathbf{Min}(\mathbf{SPDELMW}_{2c(tp)d}, \mathbf{SPCUL}_{2c(tp)d}) + \ldots + \mathbf{Min}(\mathbf{SPDELMW}_{nc(tp)d}, \mathbf{SPCUL}_{nc(tp)d}))$$

The above variables are defined as follows:

Variable	Unit	Description
$\mathrm{ERSPAMT}_{qc(tp)d}$	$	*ERS Payment Amount per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—ERS total payment to QSE *q* for ERS Contract Period *c,* and ERS Time Period *tp* and ERS service type *d*.
$\mathrm{COMPAMT}_{qc(tp)d}$	$	*Competitive Amount per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—ERS total payment to QSE *q* for all competitively procured ERS Resources delivered for ERS Contract Period *c*, and ERS Time Period *tp* and ERS service type *d*.

SPAMT $_{qc(tp)d}$	$	*Self-Procured Amount per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—ERS total payment to QSE *q* for its self-provided ERS Resources for ERS Contract Period *c*, ERS Time Period *tp* and ERS service type *d*.
ERSPAMTQSETOT $_{q}$	$	*ERS Payment QSE Total per QSE*—The total ERS total payments to QSE *q*.
ERSPAMTTOT $_{c(tp)d}$	$	*ERS Payment Amount Total per ERS Contract Period per ERS Time Period per ERS Service Type*—Total of all ERS payments for ERS Contract Period *c*, ERS Time Period *tp* and ERS service type *d*.
ERSPRICE $_{qc(tp)d}$	$/MW per hour	*Price of the Highest Offer Cleared per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—Contracted clearing price for QSE *q* for ERS Contract Period *c*, ERS Time Period *tp* and ERS service type *d*.
COMPDELMW $_{qce(tp)d}$	MW	*Competitive Delivered MW per QSE per ERS Contract Period per ERS Resource per ERS Time Period per ERS Service Type*—ERS capacity delivered by the QSE *q* for ERS Contract Period *c,* competitive ERS Resource *e*, ERS Time Period *tp* and ERS service type *d*.
TPH $_{c(tp)d}$	Hours	Hours in ERS Time Period *tp* for ERS Contract Period *c*, and ERS service type *d*. For ERS Resources *e* whose obligation is not exhausted in an ERS Contract Period *c,* the number of hours in that ERS Time Period *tp* in that ERS Contract Period *c*. For ERS Resources *e* whose obligation is exhausted in an ERS Contract Period *c*, the number of hours in that ERS Time Period *tp* from the beginning of the ERS Contract Period *c* to the end of the ERS Standard Contract Term.
ERSTESTPF $_{qred}$	None	*ERS Test Performance Factor per QSE per ERS Standard Contract Term per ERS Resource per ERS Service Type*—Test performance factor for QSE *q* in ERS Standard Contract Term *r* for ERS Resource *e* and ERS service type *d* as calculated pursuant to Section 8.1.3.3.1, Suspension of Qualification of Non-Weather-Sensitive Emergency Response Service Resources and/or their Qualified Scheduling Entities.
SPDELMW $_{qc(tp)d}$	MW	*Self-Provided Delivered MW per QSE per ERS Contract Period per ERS Resource per ERS Time Period per ERS Service Type*—Total ERS capacity self-provided and delivered by QSE *q* for ERS Contract Period *c,* ERS Resource *e*, ERS Time Period *tp* and ERS service type *d*.
COMPDELQSEMW $_{qc(tp)d}$	MW	*Competitive Delivered MW Total per QSE per ERS Contract Period per ERS Time Period per ERS service type*—Total ERS competitive capacity delivered by QSE *q* for ERS Contract Period *c* and ERS Time Period *tp* and ERS service type *d*.
COMPDELMWTOT $_{c(tp)d}$	MW	*Competitive Delivered MW Total per ERS Contract Period per ERS Time Period per ERS Service Type*—Total ERS competitive capacity delivered by all QSEs for ERS Contract Period *c*, ERS Time Period *tp* and ERS service type *d*.
SPDELQSEMW $_{qc(tp)d}$	MW	*Self-Provision Delivered Total MW per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—Total ERS self-provision capacity delivered by QSE *q* for ERS Contract Period *c* and ERS Time Period *tp* and ERS service type *d*.

$\text{SPDELMWTOT}_{c(tp)d}$	MW	*Self-Provision Delivered Total MW per ERS Contract Period per ERS Time Period per ERS Service Type*—Total ERS self-provision capacity delivered by all QSE q for ERS Contract Period c and ERS Time Period tp and ERS service type d.
$\text{COMPOFFERMW}_{qce(tp)d}$	MW	*Competitive Offered MW Total per QSE per ERS Contract Period per ERS Resource per ERS Time Period per ERS Service Type*—ERS capacity offered by QSE q for ERS Contract Period c, competitive ERS Resource e and ERS Time Period tp and ERS service type d.
ERSAFWT_{qcd}	None	*Availability Settlement weighting factor per QSE per ERS Contract Period per ERS Service Type*—The weighting factor for QSE q for ERS Contract Period c, and ERS service type d to apply for Settlement as calculated pursuant to Section 8.1.3.1.3.3, Contract Period Availability Calculations for Emergency Response Service Resources.
ERSAFCOMB_{qrd}	None	*Time- and Capacity-Weighted ERS Availability Factor per QSE per ERS Standard Contract Term per ERS Service Type*—The availability factor for QSE q for ERS Standard Contract Term r and ERS service type d, as calculated pursuant to Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities.
ERSEPF_{qrd}	None	*ERS Event Performance Factor per QSE per ERS Standard Contract Term per ERS Service Type*—Event performance factor for QSE q in ERS Standard Contract Term r and ERS service type d as calculated pursuant to Section 8.1.3.3.1.
$\text{SPCUL}_{qc(tp)d}$	MW	*Self-Provision Capacity Upper Limit per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—The ERS Self-Provision Capacity Upper Limit calculated by ERCOT for a self-providing QSE for ERS Contract Period c and ERS Time Period tp by simultaneously solving for all QSEs' obligations with the constraint that each QSE's ERS Self-Provision Capacity Upper Limit does not exceed its obligation.
$\text{SPOFFERMW}_{qce(tp)d}$	MW	*Self-Provision Offer MW per QSE per ERS Contract Period per ERS Resource per ERS Time Period per ERS Service Type*—ERS capacity offered as self-provision by QSE q for ERS Contract Period c, ERS Resource e, ERS Time Period tp and ERS service type d.
$\text{ERSLRS}_{qc(tp)}$	None	*ERS Load Ratio Share per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—ERS LRS for QSE q for ERS Contract Period c, ERS Time Period tp and ERS service type d, calculated starting with the first hour of the ERS Contract Period and ending with the earlier of the last hour of the ERS Contract Period or the hour containing the recall instruction in an ERS deployment event that results in the exhaustion of a QSE portfolio's ERS obligation. If the resultant QSE-level share is negative, the QSE's share will be set to zero and all other QSE shares will be adjusted on a pro rata basis such that the sum of all shares is equal to one.
q	None	A QSE.
c	None	ERS Contract Period.
r	None	ERS Standard Contract Term.
tp	None	Hours in an ERS Time Period.

e	None	An ERS Resource procured from a QSE for an ERS Contract Period.
co	None	The number of competitive ERS Resources procured from a QSE for an ERS Contract Period.
s	None	The number of self-provided ERS Resources procured from a QSE for an ERS Contract Period.
n	None	The number of QSEs for an ERS Contract Period.
d	None	ERS service type (Weather-Sensitive ERS-10, Non-Weather-Sensitive ERS-10, Weather-Sensitive ERS-30, or Non-Weather-Sensitive ERS-30).

6.6.11.2 Emergency Response Service Capacity Charge

(1) ERCOT shall allocate costs for an ERS service type and ERS Contract Period based on the LRS of each QSE during each ERS Time Period in an ERS Contract Period. A QSE's LRS for an ERS Time Period shall be the QSE's total Load for the ERS Time Period divided by the total ERCOT Load in the ERS Time Period. For the first Settlement of the ERS Contract Period as described in paragraph (1) of Section 9.14.5, Settlement of Emergency Response Service, LRS will be calculated using the latest Settlement Load for each Operating Day in the ERS Contract Period. For the resettlement of the ERS Contract Period as described in paragraph (2) of Section 9.14.5, the LRS will be calculated using the true-up Load for each Operating Day in the ERS Contract Period.

(2) ERCOT shall calculate each QSE's ERS capacity charge as follows:

$$\mathbf{LAERSAMT}_{qc(tp)d} = \mathbf{ERSLRS}_{qc(tp)d} * \mathbf{ERSPAMTTOT}_{c(tp)d}$$

$$\mathbf{LAERSAMTQSETOT}_{q} = \sum_{tp} \mathbf{LAERSAMT}_{q(tp)d}$$

The above variables are defined as follows:

Variable	Unit	Description
$\mathrm{ERSPAMTTOT}_{c(tp)d}$	$	*ERS Payment Amount Total per ERS Contract Period per ERS Time Period per ERS Service Type*—Total of all ERS payments for ERS Contract Period *c,* ERS Time Period *tp* and ERS service type *d*.
$\mathrm{ERSLRS}_{qc(tp)d}$	None	*ERS Load Ratio Share per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—ERS LRS for QSE *q* for ERS Contract Period *c,* ERS Time Period *tp* and ERS service type *d,* calculated starting with the first hour of the ERS Contract Period and ending with the earlier of the last hour of the ERS Contract Period or the hour containing the recall instruction in an ERS deployment event that results in the exhaustion of a QSE portfolio's ERS obligation. If the resultant QSE-level share is negative, the QSE's share will be set to zero and all other QSE shares will be adjusted on a pro rata basis such that the sum of all shares is equal to one.

LAERSAMT $_{qc(tp)d}$	$	*Load-Allocated ERS Amount per QSE per ERS Contract Period per ERS Time Period per ERS Service Type*—ERS charge for QSE *q* for ERS Contract Period *c,* ERS Time Period *tp* and ERS service type *d*.
LAERSAMTQSETOT $_{q}$	$	*Load-Allocated ERS Amount QSE Total per QSE*—The total ERS charge for QSE *q*.
q	None	A QSE.
c	None	ERS Contract Period.
tp	None	An ERS Time Period.
d	None	ERS service type (Weather-Sensitive ERS-10, Non-Weather-Sensitive ERS-10, Weather-Sensitive ERS-30, or Non-Weather-Sensitive ERS-30).

6.6.12 Make-Whole Payment for Switchable Generation Resources Committed for Energy Emergency Alert (EEA)

(1) If ERCOT directs a Switchable Generation Resource (SWGR) to switch to the ERCOT Control Area for an actual or anticipated Energy Emergency Alert (EEA) condition, ERCOT shall pay the QSE representing the SWGR a Switchable Generation Make-Whole Payment (SWMWAMT) as calculated in Section 6.6.12.1, Switchable Generation Make-Whole Payment, if the QSE has:

(a) Not opted out of the RUC instruction, which may be a verbal RUC, per the process described in paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) Complied with the RUC instruction, which may be a verbal RUC, to switch to the ERCOT Control Area and start the Resource;

(c) Submitted a timely Settlement and billing dispute, including the following items:

(i) An attestation signed by an officer or executive with authority to bind the QSE stating that the information contained in the submission is accurate;

(ii) The dollar amount and calculation of the financial loss, if applicable, by Settlement Interval for:

(A) Energy and ancillary service imbalance costs assessed under the non-ERCOT Control Area Operator's (CAO's) settlement process arising from DAM energy and ancillary service obligations of the SWGR in the non-ERCOT Control Area for the time period starting at the initiation of the ramp-down in the non-ERCOT Control Area to two hours following the time ERCOT released the SWGR;

(B) Incremental fuel costs incurred to comply with the instruction. Incremental fuel costs may include only those fuel costs described in Section 9.14.9, Incremental Fuel Costs for Switchable Generation Make-Whole Payment Disputes;

(C) Make-Whole Payment distribution costs for the commitment of generation resources in the non-ERCOT Control Area arising from the need to replace the energy and ancillary service obligations of the generation instructed via a RUC instruction to switch into the ERCOT Control Area;

(D) Pipeline imbalance penalty costs arising from the SWGR not consuming or consuming over its contracted fuel quantities as a result of a switch from a non-ERCOT Control Area as requested by ERCOT. Fuel imbalance penalty costs are limited to those costs assessed for the period starting at the initiation of the ramp-down in the non-ERCOT Control Area to two hours following the time ERCOT released the SWGR;

(iii) Sufficient documentation to support the QSE's calculation of the amount of the financial loss and all submitted costs.

(2) For a SWGR without approved verifiable costs, the startup and minimum-energy costs will be determined based on generic costs as described in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps. If generic costs are insufficient to cover startup and minimum-energy costs of the SWGR, the QSE may provide documentation and request that generic costs be replaced by proxy costs, if available, as determined by ERCOT.

(3) For a SWGR that is a Combined Cycle Generation Resource, all operating costs are those costs for the Combined Cycle Generation Resource within the Combined Cycle Train that is instructed for the hour. If the QSE representing a Combined Cycle Generation Resource complies with a RUC instruction by ERCOT to transition from one Combined Cycle Generation Resource to a different Combined Cycle Generation Resource within the Combined Cycle Train, the incremental cost to transition shall be included in the Switchable Generation Start-Up Cost (SWSUC), as calculated in Section 6.6.12.1, for the Combined Cycle Resource.

(4) A QSE representing a SWGR that is committed through an ERCOT instruction to switch to the ERCOT Control Area may recover lost revenue, net of saved fuel costs, attributable to a reduction in the output of other ERCOT-connected generators that are part of a Combined Cycle Train that includes the RUC-committed SWGR if the following conditions have been met:

(a) The QSE had to turn off one or more generators that were physically connected to the non-ERCOT Control Area in order to achieve the instructed switch, or had to turn off one or more generators that were physically connected to the ERCOT System in order to switch back to the non-ERCOT Control Area, in which case it must have completed the shutdown sequence within 60 minutes of the end of the RUC instruction; and

(b) As a consequence of turning off one or more generators to facilitate a switch described in paragraph (a) above, the output of one or more generators in the configuration operating in ERCOT at the time of the instruction had to be reduced.

(5) The lost revenue, net of saved fuel costs, described in paragraph (4) above shall be included in the Switchable Generation Cost Guarantee (SWCG), as calculated in Section 6.6.12.1, for the Combined Cycle Generation Resource.

(6) For a SWGR switching from a non-ERCOT Control Area, the compensation described in paragraph (4) above shall be determined for the period from the commencement of the shutdown sequence of the switched unit in the non-ERCOT Control Area until breaker close in the ERCOT Control Area. For a SWGR switching to a non-ERCOT Control Area within 60 minutes of the end of the RUC instruction, the compensation described in paragraph (4) above shall be determined for the period from the commencement of the shutdown sequence of the unit in the ERCOT System until breaker close in the non-ERCOT Control Area, with a maximum duration equal to the duration of the switch from the non-ERCOT Control Area to ERCOT pursuant to the RUC instruction.

(7) A QSE that is entitled to compensation under paragraph (4) above, or the Resource Entity for the affected SWGR, must provide the following documentation for the Combined Cycle Train to verify the lost revenue:

(a) Documentation of the Real-Time output of each unit in the Combined Cycle Train, whether operating in ERCOT or in the non-ERCOT Control Area;

(b) For thermal units, the Input-Output Equation or other documentation that allows for calculating the reduction in fuel consumption if the unit had to reduce generation;

(c) Documentation of the time the shutdown sequence started while switching to ERCOT, and if the QSE seeks recovery of lost revenues for a switch to the non-ERCOT Control Area, documentation of the time the breaker closed in the non-ERCOT Control Area, which is subject to verification with the non-ERCOT Control Area operator;

(d) Documentation showing which combustion turbine of the Combined Cycle Generation Resource is providing the auxiliary service; and

(e) Any other technical documentation ERCOT finds necessary to verify the performance and physical characteristics of the Combined Cycle Train or any component thereof, such as thermal balance diagrams.

(8) The Startup Cost for the SWGR shall include the cost for starting in the ERCOT Control Area and, if the SWGR starts up in the non-ERCOT Control Area within 24 hours of

being released from ERCOT, the cost of starting in the non-ERCOT Control Area, which will be based on the same warmth state.

(9) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT's request. ERCOT will provide Notice of its acceptance or rejection of the claim for the SWMWAMT within 15 Business Days of the updated submission.

(10) If ERCOT denies all or a portion of a QSE's non-ERCOT Control Area costs, pursuant to paragraph (1)(c)(ii) above, the QSE may submit a request for ADR as described in Section 20, Alternative Dispute Resolution Procedure.

6.6.12.1 Switchable Generation Make-Whole Payment

(1) To compensate QSEs representing SWGRs that switch to the ERCOT Control Area from a non-ERCOT Control Area pursuant to an ERCOT RUC instruction for an actual or anticipated EEA condition, ERCOT shall calculate a Switchable Generation Make-Whole Payment (SWMWAMT) for an Operating Day, allocated to each instructed Operating Hour as follows:

$$\mathbf{SWMWAMT}_{q,\,r} = \mathbf{(-1) * Max\ (0, (SWCG}_{q,\,r,\,d} - \mathbf{SWRTREV}_{q,\,r,\,d}\mathbf{))\ /\ SWIHR}_{q,\,r,\,d}$$

Where:

$$\text{SWCG}_{q,\,r,\,d} = \text{SWSUC}_{q,\,r,\,d} + \text{SWMEC}_{q,\,r,\,d} + \text{SWOC}_{q,\,r,\,d} + \text{SWAC}_{q,\,r,\,d} + \text{SWPSLR}_{q,\,r,\,d}$$

$$\text{SWRTREV}_{q,\,r,\,d} = \text{Max}\ [0, \sum_{i}(\text{RTSPP}_{p,\,i} * \text{RTMG}_{q,\,r,\,i} + (-1) * (\text{EMREAMT}_{q,\,r,\,p,\,i} + \text{VSSVARAMT}_{q,\,r,\,i} + \text{VSSEAMT}_{q,\,r,\,i}) + \text{Max}(0, (\text{RTOLHSLRA}_{q,\,r,\,p,\,i} - \text{RTMGA}_{q,\,r,\,p,\,i}) * (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i})))]$$

$$\text{SWAC}_{q,\,r,\,d} = \text{SWFC}_{q,\,r,\,d} + \text{SWEIC}_{q,\,r,\,d} + \text{SWASIC}_{q,\,r,\,d} + \text{SWMWDC}_{q,\,r,\,d} + \text{SWFIPC}_{q,\,r,\,d}$$

$$\text{SWPSLR}_{q,\,r,\,d} = \sum_{i}(\text{RTSPP}_{p,\,i} * \text{RTLPX}_{q,\,r,\,i}) - (\text{FIP}+\text{FA}) * \text{SFC}_{d}$$

If ERCOT has approved verifiable costs for the SWGR:

$$\text{SWSUC}_{q,\,r,\,d} = \sum_{s}\ [\text{SWSF} * (\text{DAFCRS}_{r,\,s} * (\text{GASPERSU}_{r,\,s} * \text{FIP} + \text{OILPERSU}_{r,\,s} * \text{FOP} + \text{SFPERSU}_{r,\,s} * \text{SFP}) + \text{VOMS}_{r,\,s})] + \text{ADJSWSUC}_{q,\,r,\,d}$$

$$\text{SWMEC}_{q,\,r,\,d} = \sum_{i} ((\text{AHR}_{r,\,i} * (\text{GASPERME}_{r} * \text{FIP} + \text{OILPERME}_{r} * \text{FOP} + \text{SFPERME}_{r} * \text{SFP} + \text{FA}_{r}) + \text{VOMLSL}_{r}) * \text{Min}\,(\text{LSL}_{q,\,r,\,i} * (¼), \text{RTMG}_{q,\,r,\,i}))$$

$$\text{SWOC}_{q,\,r,\,d} = \sum_{i} [(\text{AHR}_{r,\,i} * ((\text{GASPEROL}_{r} * \text{FIP} + \text{OILPEROL}_{r} * \text{FOP} + \text{SFPEROL}_{r} * \text{SFP}) + \text{FA}_{r}) + \text{OM}_{r}) * \text{Max}(0, (\text{RTMG}_{q,\,r,\,i} - \text{LSL}_{q,\,r,\,i} * (¼)))] - \text{OPC}_{r,\,d}$$

Where,

$$\text{OPC}_{r,\,d} = \sum_{i} ((\text{PAHR}_{r,\,i} * (\text{FIP} + \text{FA}) + \text{OM}_{r}) * \text{AENG}_{r,\,i})$$

If ERCOT has not approved verifiable costs for the SWGR:

$$\text{SWSUC}_{q,\,r,\,d} = \sum_{s} (\text{SWSF} * \text{RCGSC}_{s,\,rc}) + \text{ADJSWSUC}_{q,\,r,\,d}$$

$$\text{SWMEC}_{q,\,r,\,d} = \sum_{i} (\text{RCGMEC}_{i,\,rc} * \text{Min}\,(\text{LSL}_{q,\,r,\,i} * (¼), \text{RTMG}_{q,\,r,\,i}))$$

$$\text{SWOC}_{q,\,r,\,d} = \sum_{i} ((\text{PAHR}_{r,\,i} * \text{FIP} + \text{STOM}_{rc}) * \text{Max}(0, (\text{RTMG}_{q,\,r,\,i} - \text{LSL}_{q,\,r,\,i} * (¼)))) - \text{OPC}_{r,\,d}$$

Where,

$$\text{OPC}_{r,\,d} = \sum_{i} ((\text{PAHR}_{r,\,i} * \text{FIP} + \text{STOM}_{rc}) * \text{AENG}_{r,\,i})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
SWMWAMT $_{q,\,r}$	\$	*Switchable Generation Make-Whole Payment*—The Switchable Generation Make-Whole Payment to the QSE *q,* for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
SWCG $_{q,\,r,\,d}$	\$	*Switchable Generation Cost Guarantee*—The sum of eligible Startup Costs, minimum-energy costs, operating costs, and other Switchable Generation approved costs for Resource *r* represented by QSE *q* for all instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
OPC $_{r,\,d}$	\$	*Operational Cost* – The operational cost for the Resource *r* for the Operating Day *d* in the non-ERCOT Control Area. The operating costs represent the costs the Resource would have incurred to generate the awarded energy in the non-ERCOT Control Area Day-Ahead market absent a request to switch to ERCOT. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition
AENG $_{r,\,i}$	MWh	*Awarded Energy Non-ERCOT Day-Ahead Market* – The awarded energy in the non-ERCOT Day-Ahead Market for the Resource *r* during the Interval *i*. The awarded energy in the non-ERCOT Control Area Day-Ahead market represents the energy award for the interval that was not generated by the Resource due to the switch to ERCOT. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
SWSUC $_{q\,,r,\,d}$	$	*Switchable Generation Start-Up Cost* —The Startup Costs for Resource *r* represented by QSE *q* for startup hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
SWPSLR $_{q\,,r,\,d}$	$	*Switchable Generation Physical Switch Lost Revenue* – The loss of revenue, net of any saved costs including avoided fuel consumption, experienced by the QSE when the Combined Cycle Generation Resource operating in ERCOT must reduce its output to accommodate a switch from a non-ERCOT Control Area of one or more turbines needed to achieve a Combined Cycle Generation Resource configuration instructed by ERCOT. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTLPX $_{q,\,r,\,i}$	MWh	*Real-Time Proxy Generation per QSE per Resource by Settlement Interval*—The Real-Time energy that was not generated in ERCOT by Combined Cycle Train, *r*, represented by QSE *q*, for the 15-minute Settlement Interval *i*, due to a reduction in output that was necessary to facilitate a switch of another unit in the same Combined Cycle Train to the ERCOT System from a non-ERCOT Control Area, or to a non-ERCOT Control Area from the ERCOT System, when the switch is instructed by ERCOT. During a shutdown to switch to ERCOT, the value of RTLPX will be determined based on the reduced generation, by interval, for the period starting from the commencement of the shutdown sequence in the non-ERCOT Control Area until breaker close in ERCOT. The reduction in generation shall be determined based on the last metered output value for the Combined Cycle Generation Resource operating in ERCOT immediately prior to the commencement of the shutdown sequence in the non-ERCOT Control Area as compared with the actual metered output during the relevant period, but only to the extent ERCOT determines the reduction in output was necessary to facilitate the switch. During a shutdown after an ERCOT release of the SWGR, the value of RTLPX will be determined based on the reduced generation, by interval, for the period starting from the commencement of the shutdown sequence in the ERCOT Control Area until breaker close in the non-ERCOT Control Area, with a maximum duration equal to the duration of the switch from the non-ERCOT Control Area to ERCOT pursuant to the RUC instruction. This proxy value will apply only if the QSE shuts down the unit within 60 minutes after the ERCOT release. The reduction in generation shall be determined based on the last metered output value for the Combined Cycle Generation Resource operating in ERCOT immediately prior to the commencement of the shutdown sequence in ERCOT, as compared with the actual metered output during the relevant period, but only to the extent ERCOT determines the reduction in output was necessary to facilitate the switch.

Variable	Unit	Definition
SFC_{d}	MMBtu	*Saved Fuel Consumption* — Fuel quantity saved due to an output reduction of the combustion turbine(s) operating in ERCOT during the relevant period if necessary to accommodate the switch to and from the ERCOT area.
SWSF	none	*Switchable Generation Startup Factor* —The Switchable Generation Startup Factor for an SWGR. The SWSF shall be set to a value of 2 if the SWGR has a COP Resource Status of EMRSWGR within 24 hours of being released by the ERCOT Operator. Otherwise, the SWSF shall be set to a value of 1.
$SWMEC_{q, r, d}$	$	*Switchable Generation Minimum Energy Cost* —The minimum energy costs for Resource *r* represented by QSE *q* during instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$SWOC_{q, r, d}$	$	*Switchable Generation Operating Cost* —The operating costs for Resource *r* represented by QSE *q* during instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Switchable generation operating cost represents the Real-Time operating costs in ERCOT reduced by the savings in operating costs not incurred due to the switch from the non-ERCOT Control Area.
$SWAC_{q, r, d}$	$	*Switchable Generation Approved Costs* – The total amount of the calculation of financial loss, as submitted by the QSE *q* for the Resource *r,* as approved by ERCOT for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$SWFC_{q, r, d}$	$	*Switchable Generator Fuel Cost* —The incremental fuel costs and fees for Resource *r* represented by QSE *q* for all instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Incremental fuel costs must be based on those costs incurred as described in Section 9.14.9, Incremental Fuel Costs for Switchable Generation Make-Whole Payment.
$SWFIPC_{q, r, d}$	$	*Switchable Generator Fuel Imbalance Penalty Cost* —The fuel imbalance penalty cost for Resource *r* represented by QSE *q*, for the Operating Day, arising from the SWGR not consuming its contracted fuel quantities as a result of a switch from a non-ERCOT Control Area as requested by ERCOT. Fuel imbalance penalty costs are limited to those costs assessed for the period starting at the initiation of the ramp-down in the non-ERCOT Control Area to two hours following the time ERCOT released the SWGR. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$SWEIC_{q, r, d}$	$	*Switchable Generator Energy Imbalance Cost* —The energy imbalance costs for Resource *r* represented by QSE *q* for instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Energy imbalance costs represent Real-Time imbalance charges for the amount of energy the SWGR was not able to provide as required by its DAM commitment from the non-ERCOT Control Area, starting from the beginning of the ramp-down period in the other grid to two hours following the time ERCOT released the Resource.

Variable	**Unit**	**Definition**
SWASIC $_{q,\ r,\ d}$	$	*Switchable Generator Ancillary Services Imbalance Cost* —The Ancillary Service imbalance costs for Resource *r* represented by QSE *q* for instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Ancillary Service imbalance costs represent Real-Time imbalance charges for the amount of Ancillary Services the SWGR was not able to provide as required by its Day-Ahead commitment from the non-ERCOT Control Area, starting from the time of shutdown in the other grid to two hours following the time ERCOT released the Resource.
SWMWDC $_{q,\ r,\ d}$	$	*Switchable Generator Make-Whole Payment Distribution Cost* —The Make-Whole Payment distribution costs for Resource *r* represented by QSE *q* for instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Make-Whole Payment distribution costs represent charges from non-ERCOT Control Area from the time of shutdown in the other grid to two hours following the time ERCOT released the Resource.
SWRTREV $_{q,\ r,\ d}$	$	*Switchable Generation Real-Time Revenues* – The sum of energy revenues for the Resource *r,* represented by QSE *q,* during all instructed hours for the Operating Day *d.* Where for a Combined Cycle Train, Resource *r* is the Combined Cycle Train.
GASPERSU $_{r,\ s}$	none	*Percent of Natural Gas to Operate per Start*—The percentage of natural gas used by Resource *r* to operate per start *s*, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
OILPERSU $_{r,\ s}$	none	*Percent of Oil to Operate per Start*—The percentage of fuel oil used by Resource *r* to operate per start *s*, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
SFPERSU $_{r,\ s}$	none	*Percent of Solid Fuel to Operate per Start*—The percentage of solid fuel used by Resource *r* to operate per start *s*, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
GASPERME $_{r}$	None	*Percent of Natural Gas to Operate at LSL*—The percentage of natural gas used by Resource *r* to operate at LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
OILPERME $_{r}$	None	*Percent of Oil to Operate at LSL*—The percentage of fuel oil used by Resource *r* to operate at LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
SFPERME $_{r}$	None	*Percent of Solid Fuel to Operate at LSL*—The percentage of solid fuel used by Resource *r* to operate at LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DAFCRS $_{r,\ s}$	MMBtu/Start	*Day-Ahead Actual Fuel Consumption Rate per Start*—The actual fuel consumption rate for Resource *r* to startup per start type *s*, adjusted by VOXR as defined in the Verifiable Cost Manual. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. For additional information, see Verifiable Cost Manual Section 3.3, Startup Fuel Consumption.

Variable	**Unit**	**Definition**
$VOMS_{r,\,s}$	\$/Start	*Variable Operations and Maintenance Cost per Start*—The operations and maintenance cost for Resource *r* to startup, per start *s*, including an adjustment for emissions costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. For additional information, see Verifiable Cost Manual Section 3.2, Submitting Startup Costs.
$VOMLSL_{r}$	\$/MWh	*Variable Operations and Maintenance Cost at LSL*—The operations and maintenance cost for Resource *r* to operate at LSL, including an adjustment for emissions costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. For additional information, see Verifiable Cost Manual Section 4.2, Submitting Minimum Energy Costs.
$LSL_{q,\,r,\,i}$	MW	*Low Sustained Limit*—The LSL of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RTMG_{q,\,r,\,i}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval by hour*—The Real-Time energy from Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$AHR_{r,\,i}$	MMBtu / MWh	*Average Heat Rate per Resource*– The verifiable average heat rate for the Resource *r*, for the operating level, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
OM_{r}	\$/MWh	*Verifiable Operations and Maintenance Cost Above LSL*– The O&M cost for Resource *r* to operate above LSL. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
$SWIHR_{q,\,r,\,d}$	none	*Switchable Generation Instructed Hours*—The total number of Switchable Generation instructed hours, for Resource *r* represented by QSE *q,* for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by ERCOT, the total number of instructed hours is calculated for the Combined Cycle Train for all switchable instructed Combined Cycle Generation Resources.
SFP	\$/MMBtu	*Solid Fuel Price*—The solid fuel index price is \$1.50.
$GASPEROL_{r}$	none	*Percent of Natural Gas to Operate Above LSL*—The percentage of natural gas used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$OILPEROL_{r}$	none	*Percent of Oil to Operate Above LSL*—The percentage of fuel oil used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$SFPEROL_{r}$	none	*Percent of Solid Fuel to Operate Above LSL*—The percentage of solid fuel used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	Unit	Definition
ADJSWSUC $_{q, r, d}$	$	*Adjustment to Switchable Generation Start-Up Cost* — Adjustment to Switchable Generation Start-up Cost for Resource *r* represented by QSE *q*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. This adjustment may include eligible startup transition costs for a Combined Cycle Train or costs for any SWGR not captured in other billing determinants.
RCGSC $_{s, rc}$	$/Start	*Resource Category Generic Startup Cost*—The Resource Category Generic Startup Cost cap for the category of the Resource *rc*, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
RCGMEC $_{i, rc}$	$/MWh	*Resource Category Generic Minimum-Energy Cost*—The Resource Category Generic Minimum Energy Cost cap for the category of the Resource *rc*, according to Section 4.4.9.2.3, for the Operating Day.
PAHR $_{r, i}$	MMBtu / MWh	*Proxy Average Heat Rate*- The proxy average heat rate for the Resource *r* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
STOM $_{rc}$	$/MWh	*Standard Operations and Maintenance Cost* - The standard O&M cost for the Resource Category *rc* for operations above LSL, shall be set to the minimum energy variable O&M costs, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
FIP	$/MMBtu	*Fuel Index Price*—As defined in Section 2.1, Definitions.
FOP	$/MMBtu	*Fuel Oil Price*—As defined in Section 2.1.
FA $_{r}$	$/MMBtu	*Fuel Adder* — The fuel adder is the average cost above the index price Resource *r* has paid to obtain fuel. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
EMREAMT $_{q, r, p, i}$	$	*Emergency Energy Amount per QSE per Settlement Point per unit per interval*—The payment to QSE *q* for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval *i*. Payment for emergency energy is made to the Combined Cycle Train.
VSSVARAMT $_{q, r, i}$	$	*Voltage Support Service VAr Amount per QSE per Generation Resource* - The payment to QSE *q* for the VSS provided by Generation Resource *r,* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Resource *r* is a Combined Cycle Train.
VSSEAMT $_{q, r, i}$	$	*Voltage Support Service Energy Amount per QSE per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource *r* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Resource *r* is a Combined Cycle Train.
RTOLHSLRA $_{q, r, p, i}$	MWh	*Real-Time Adjusted On-Line High Sustained Limit for the Resource*—The Real-Time telemetered HSL for the Resource *r* represented by QSE *q* at Resource Node *p* that is available to SCED, integrated over the 15-minute Settlement Interval *i*, as described in Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition
$\text{RTMGA}_{q, r, p, i}$	MWh	*Real-Time Adjusted Metered Generation per QSE per Settlement Point per Resource*—The adjusted metered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p* in Real-Time for the 15-minute Settlement Interval *i*, as described in Section 6.7.5. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRSVPOR_{i}	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*, as described in Section 6.7.5.
RTRDP_{i}	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder, as described in Section 6.7.5.
q	none	A QSE.
r	none	A Switchable Generation Resource.
d	none	An Operating Day containing the RUC instruction to the SWGR.
i	none	A 15-minute Settlement Interval within the hour of an Operating Day during which the SWGR is instructed by ERCOT.
s	none	An ERCOT area start that is eligible to have its costs included in the Switchable Generation Cost Guarantee.
rc	none	A Resource Category.
p	none	A Resource Node Settlement Point.

[NPRR1010 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]

(1) To compensate QSEs representing SWGRs that switch to the ERCOT Control Area from a non-ERCOT Control Area pursuant to an ERCOT RUC instruction for an actual or anticipated EEA condition, ERCOT shall calculate a Switchable Generation Make-Whole Payment (SWMWAMT) for an Operating Day, allocated to each instructed Operating Hour as follows:

$$\mathbf{SWMWAMT}_{q,r} = \mathbf{(-1) * Max\ (0, (SWCG}_{q,r,d} - \mathbf{SWRTREV}_{q,r,d})) \mathbf{/\ SWIHR}_{q,r,d}$$

Where:

$$\text{SWCG}_{q,r,d} = \text{SWSUC}_{q,r,d} + \text{SWMEC}_{q,r,d} + \text{SWOC}_{q,r,d} + \text{SWAC}_{q,r,d} + \text{SWPSLR}_{q,r,d}$$

$$\text{SWRTREV}_{q,r,d} = \text{Max}\ [0, \sum_{i}(\text{RTSPP}_{p,i} * \text{RTMG}_{q,r,i} + (-1) * (\text{EMREAMT}_{q,r,p,i} + \text{VSSVARAMT}_{q,r,i} + \text{VSSEAMT}_{q,r,i}) + \text{RTRUREV}_{q,r,i} + \text{RTRDREV}_{q,r,i} + \text{RTRRREV}_{q,r,i} + \text{RTNSREV}_{q,r,i} + \text{RTECRREV}_{q,r,i})]$$

$$\text{SWAC}_{q,r,d} = \text{SWFC}_{q,r,d} + \text{SWEIC}_{q,r,d} + \text{SWASIC}_{q,r,d} + \text{SWMWDC}_{q,r,d} + \text{SWFIPC}_{q,r,d}$$

$$\text{SWPSLR}_{q,r,d} = \sum_{i} (\text{RTSPP}_{p,i} * \text{RTLPX}_{q,r,i}) - (\text{FIP}+\text{FA}) * \text{SFC}_{d}$$

If ERCOT has approved verifiable costs for the SWGR:

$$\text{SWSUC}_{q,r,d} = \sum_{s} [\text{SWSF} * (\text{DAFCRS}_{r,s} * (\text{GASPERSU}_{r,s} * \text{FIP} + \text{OILPERSU}_{r,s} * \text{FOP} + \text{SFPERSU}_{r,s} * \text{SFP}) + \text{VOMS}_{r,s})] + \text{ADJSWSUC}_{q,r,d}$$

$$\text{SWMEC}_{q,r,d} = \sum_{i} ((\text{AHR}_{r,i} * (\text{GASPERME}_{r} * \text{FIP} + \text{OILPERME}_{r} * \text{FOP} + \text{SFPERME}_{r} * \text{SFP} + \text{FA}_{r}) + \text{VOMLSL}_{r}) * \text{Min}(\text{LSL}_{q,r,i} * (1/4), \text{RTMG}_{q,r,i}))$$

$$\text{SWOC}_{q,r,d} = \sum_{i} [(\text{AHR}_{r,i} * ((\text{GASPEROL}_{r} * \text{FIP} + \text{OILPEROL}_{r} * \text{FOP} + \text{SFPEROL}_{r} * \text{SFP}) + \text{FA}_{r}) + \text{OM}_{r}) * \text{Max}(0, (\text{RTMG}_{q,r,i} - \text{LSL}_{q,r,i} * (1/4)))] - \text{OPC}_{r,d}$$

Where,

$$\text{OPC}_{r,d} = \sum_{i} ((\text{PAHR}_{r,i} * (\text{FIP} + \text{FA}) + \text{OM}_{r}) * \text{AENG}_{r,i})$$

If ERCOT has not approved verifiable costs for the SWGR:

$$\text{SWSUC}_{q,r,d} = \sum_{s} (\text{SWSF} * \text{RCGSC}_{s,rc}) + \text{ADJSWSUC}_{q,r,d}$$

$$\text{SWMEC}_{q,r,d} = \sum_{i} (\text{RCGMEC}_{i,rc} * \text{Min}(\text{LSL}_{q,r,i} * (1/4), \text{RTMG}_{q,r,i}))$$

$$\text{SWOC}_{q,r,d} = \sum_{i} ((\text{PAHR}_{r,i} * \text{FIP} + \text{STOM}_{rc}) * \text{Max}(0, (\text{RTMG}_{q,r,i} - \text{LSL}_{q,r,i} * (1/4)))) - \text{OPC}_{r,d}$$

Where,

$$\text{OPC}_{r,d} = \sum_{i} ((\text{PAHR}_{r,i} * \text{FIP} + \text{STOM}_{rc}) * \text{AENG}_{r,i})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
SWMWAMT $_{q,r}$	$	*Switchable Generation Make-Whole Payment*—The Switchable Generation Make-Whole Payment to the QSE *q,* for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

SWCG $_{q, r, d}$	$	*Switchable Generation Cost Guarantee*—The sum of eligible Startup Costs, minimum-energy costs, operating costs, and other Switchable Generation approved costs for Resource *r* represented by QSE *q* for all instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
OPC $_{r, d}$	$	*Operational Cost* – The operational cost for the Resource *r* for the Operating Day *d* in the non-ERCOT Control Area. The operating costs represent the costs the Resource would have incurred to generate the awarded energy in the non-ERCOT Control Area Day-Ahead market absent a request to switch to ERCOT. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
AENG $_{r, i}$	MWh	*Awarded Energy Non-ERCOT Day-Ahead Market* – The awarded energy in the non-ERCOT Day-Ahead Market for the Resource *r* during the Interval *i*. The awarded energy in the non-ERCOT Control Area Day-Ahead market represents the energy award for the interval that was not generated by the Resource due to the switch to ERCOT. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
SWSUC $_{q ,r, d}$	$	*Switchable Generation Start-Up Cost* —The Startup Costs for Resource *r* represented by QSE *q* for startup hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
SWPSLR $_{q ,r, d}$	$	*Switchable Generation Physical Switch Lost Revenue* – The loss of revenue, net of any saved costs including avoided fuel consumption, experienced by the QSE when the Combined Cycle Generation Resource operating in ERCOT must reduce its output to accommodate a switch from a non-ERCOT Control Area of one or more turbines needed to achieve a Combined Cycle Generation Resource configuration instructed by ERCOT. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

RTLPX $_{q, r, i}$	MWh	*Real-Time Proxy Generation per QSE per Resource by Settlement Interval*—The Real-Time energy that was not generated in ERCOT by Combined Cycle Train, *r*, represented by QSE *q*, for the 15-minute Settlement Interval *i*, due to a reduction in output that was necessary to facilitate a switch of another unit in the same Combined Cycle Train to the ERCOT System from a non-ERCOT Control Area, or to a non-ERCOT Control Area from the ERCOT System, when the switch is instructed by ERCOT. During a shutdown to switch to ERCOT, the value of RTLPX will be determined based on the reduced generation, by interval, for the period starting from the commencement of the shutdown sequence in the non-ERCOT Control Area until breaker close in ERCOT. The reduction in generation shall be determined based on the last metered output value for the Combined Cycle Generation Resource operating in ERCOT immediately prior to the commencement of the shutdown sequence in the non-ERCOT Control Area as compared with the actual metered output during the relevant period, but only to the extent ERCOT determines the reduction in output was necessary to facilitate the switch. During a shutdown after an ERCOT release of the SWGR, the value of RTLPX will be determined based on the reduced generation, by interval, for the period starting from the commencement of the shutdown sequence in the ERCOT Control Area until breaker close in the non-ERCOT Control Area, with a maximum duration equal to the duration of the switch from the non-ERCOT Control Area to ERCOT pursuant to the RUC instruction. This proxy value will apply only if the QSE shuts down the unit within 60 minutes after the ERCOT release. The reduction in generation shall be determined based on the last metered output value for the Combined Cycle Generation Resource operating in ERCOT immediately prior to the commencement of the shutdown sequence in ERCOT, as compared with the actual metered output during the relevant period, but only to the extent ERCOT determines the reduction in output was necessary to facilitate the switch.
SFC $_{d}$	MMBtu	*Saved Fuel Consumption* — Fuel quantity saved due to an output reduction of the combustion turbine(s) operating in ERCOT during the relevant period if necessary to accommodate the switch to and from the ERCOT area.
SWSF	None	*Switchable Generation Startup Factor* —The Switchable Generation Startup Factor for an SWGR. The SWSF shall be set to a value of 2 if the SWGR has a COP Resource Status of EMRSWGR within 24 hours of being released by the ERCOT Operator. Otherwise, the SWSF shall be set to a value of 1.
SWMEC $_{q, r, d}$	$	*Switchable Generation Minimum Energy Cost* —The minimum energy costs for Resource *r* represented by QSE *q* during instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
SWOC $_{q, r, d}$	$	*Switchable Generation Operating Cost* —The operating costs for Resource *r* represented by QSE *q* during instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Switchable generation operating cost represents the Real-Time operating costs in ERCOT reduced by the savings in operating costs not incurred due to the switch from the non-ERCOT Control Area.

$SWAC_{q, r, d}$	$	*Switchable Generation Approved Costs* – The total amount of the calculation of financial loss, as submitted by the QSE *q* for the Resource *r,* as approved by ERCOT for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$SWFC_{q, r, d}$	$	*Switchable Generator Fuel Cost* —The incremental fuel costs and fees for Resource *r* represented by QSE *q* for all instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Incremental fuel costs must be based on those costs incurred as described in Section 9.14.9, Incremental Fuel Costs for Switchable Generation Make-Whole Payment.
$SWFIPC_{q, r, d}$	$	*Switchable Generator Fuel Imbalance Penalty Cost* —The fuel imbalance penalty cost for Resource *r* represented by QSE *q*, for the Operating Day, arising from the SWGR not consuming its contracted fuel quantities as a result of a switch from a non-ERCOT Control Area as requested by ERCOT. Fuel imbalance penalty costs are limited to those costs assessed for the period starting at the initiation of the ramp-down in the non-ERCOT Control Area to two hours following the time ERCOT released the SWGR. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$SWEIC_{q, r, d}$	$	*Switchable Generator Energy Imbalance Cost* —The energy imbalance costs for Resource *r* represented by QSE *q* for instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Energy imbalance costs represent Real-Time imbalance charges for the amount of energy the SWGR was not able to provide as required by its DAM commitment from the non-ERCOT Control Area, starting from the beginning of the ramp-down period in the other grid to two hours following the time ERCOT released the Resource.
$SWASIC_{q, r, d}$	$	*Switchable Generator Ancillary Services Imbalance Cost* —The Ancillary Service imbalance costs for Resource *r* represented by QSE *q* for instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Ancillary Service imbalance costs represent Real-Time imbalance charges for the amount of Ancillary Services the SWGR was not able to provide as required by its Day-Ahead commitment from the non-ERCOT Control Area, starting from the time of shutdown in the other grid to two hours following the time ERCOT released the Resource.
$SWMWDC_{q, r, d}$	$	*Switchable Generator Make-Whole Payment Distribution Cost* —The Make-Whole Payment distribution costs for Resource *r* represented by QSE *q* for instructed hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. Make-Whole Payment distribution costs represent charges from non-ERCOT Control Area from the time of shutdown in the other grid to two hours following the time ERCOT released the Resource.
$SWRTREV_{q, r, d}$	$	*Switchable Generation Real-Time Revenues* – The sum of energy revenues for the Resource *r,* represented by QSE *q,* during all instructed hours for the Operating Day *d*. Where for a Combined Cycle Train, Resource *r* is the Combined Cycle Train.

GASPERSU $_{r, s}$	none	*Percent of Natural Gas to Operate per Start*—The percentage of natural gas used by Resource *r* to operate per start *s*, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
OILPERSU $_{r, s}$	none	*Percent of Oil to Operate per Start*—The percentage of fuel oil used by Resource *r* to operate per start *s*, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
SFPERSU $_{r, s}$	none	*Percent of Solid Fuel to Operate per Start*—The percentage of solid fuel used by Resource *r* to operate per start *s*, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
GASPERME $_{r}$	None	*Percent of Natural Gas to Operate at LSL*—The percentage of natural gas used by Resource *r* to operate at LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
OILPERME $_{r}$	None	*Percent of Oil to Operate at LSL*—The percentage of fuel oil used by Resource *r* to operate at LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
SFPERME $_{r}$	None	*Percent of Solid Fuel to Operate at LSL*—The percentage of solid fuel used by Resource *r* to operate at LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DAFCRS $_{r, s}$	MMBtu/Start	*Day-Ahead Actual Fuel Consumption Rate per Start*—The actual fuel consumption rate for Resource *r* to startup per start type *s*, adjusted by VOXR as defined in the Verifiable Cost Manual. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. For additional information, see Verifiable Cost Manual Section 3.3, Startup Fuel Consumption.
VOMS $_{r, s}$	$/Start	*Variable Operations and Maintenance Cost per Start*—The operations and maintenance cost for Resource *r* to startup, per start *s*, including an adjustment for emissions costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. For additional information, see Verifiable Cost Manual Section 3.2, Submitting Startup Costs.
VOMLSL $_{r}$	$/MWh	*Variable Operations and Maintenance Cost at LSL*—The operations and maintenance cost for Resource *r* to operate at LSL, including an adjustment for emissions costs. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. For additional information, see Verifiable Cost Manual Section 4.2, Submitting Minimum Energy Costs.
LSL $_{q, r, i}$	MW	*Low Sustained Limit*—The LSL of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

RTMG $_{q, r, i}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval by hour*—The Real-Time energy from Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
AHR $_{r, i}$	MMBtu / MWh	*Average Heat Rate per Resource–* The verifiable average heat rate for the Resource *r*, for the operating level, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
OM $_{r}$	$/MWh	*Verifiable Operations and Maintenance Cost Above LSL–* The O&M cost for Resource *r* to operate above LSL. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
SWIHR $_{q, r, d}$	none	*Switchable Generation Instructed Hours*—The total number of Switchable Generation instructed hours, for Resource *r* represented by QSE *q,* for the Operating Day *d*. When one or more Combined Cycle Generation Resources are committed by ERCOT, the total number of instructed hours is calculated for the Combined Cycle Train for all switchable instructed Combined Cycle Generation Resources.
SFP	$/MMBtu	Solid Fuel Price—The solid fuel index price is $1.50.
GASPEROL $_{r}$	none	*Percent of Natural Gas to Operate Above LSL*—The percentage of natural gas used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
OILPEROL $_{r}$	none	*Percent of Oil to Operate Above LSL*—The percentage of fuel oil used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
SFPEROL $_{r}$	none	*Percent of Solid Fuel to Operate Above LSL*—The percentage of solid fuel used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
ADJSWSUC $_{q, r, d}$	$	*Adjustment to Switchable Generation Start-Up Cost* — Adjustment to Switchable Generation Start-up Cost for Resource *r* represented by QSE *q*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. This adjustment may include eligible startup transition costs for a Combined Cycle Train or costs for any SWGR not captured in other billing determinants.
RCGSC $_{s, rc}$	$/Start	*Resource Category Generic Startup Cost*—The Resource Category Generic Startup Cost cap for the category of the Resource *rc*, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
RCGMEC $_{i, rc}$	$/MWh	*Resource Category Generic Minimum-Energy Cost*—The Resource Category Generic Minimum Energy Cost cap for the category of the Resource *rc*, according to Section 4.4.9.2.3, for the Operating Day.

$\text{PAHR}_{r, i}$	MMBtu / MWh	*Proxy Average Heat Rate*- The proxy average heat rate for the Resource r for the 15-minute Settlement Interval i. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.
STOM_{rc}	$/MWh	*Standard Operations and Maintenance Cost* - The standard O&M cost for the Resource Category rc for operations above LSL, shall be set to the minimum energy variable O&M costs, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs.
$\text{RTSPP}_{p, i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at Settlement Point p, for the 15-minute Settlement Interval i.
FIP	$/MMBtu	*Fuel Index Price*—As defined in Section 2.1, Definitions.
FOP	$/MMBtu	*Fuel Oil Price*—As defined in Section 2.1.
FA_{r}	$/MMBtu	*Fuel Adder* — The fuel adder is the average cost above the index price Resource r has paid to obtain fuel. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
$\text{EMREAMT}_{q, r, p, i}$	$	*Emergency Energy Amount per QSE per Settlement Point per unit per interval*—The payment to QSE q for the additional energy or Ancillary Services produced or consumed by Resource r at Resource Node p in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval i. Payment for emergency energy is made to the Combined Cycle Train.
$\text{VSSVARAMT}_{q, r, i}$	$	*Voltage Support Service VAr Amount per QSE per Generation Resource* - The payment to QSE q for the VSS provided by Generation Resource r, for the 15-minute Settlement Interval i. Where for a Combined Cycle Resource r is a Combined Cycle Train.
$\text{VSSEAMT}_{q, r, i}$	$	*Voltage Support Service Energy Amount per QSE per Generation Resource*—The lost opportunity payment to QSE q for ERCOT-directed VSS from Generation Resource r for the 15-minute Settlement Interval i. Where for a Combined Cycle Resource r is a Combined Cycle Train.
$\text{RTRUREV}_{q, r}$	$	*Real-Time Reg-Up Revenue*— The Real-Time Reg-Up revenue for QSE q calculated for Resource r for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
$\text{RTRDREV}_{q, r}$	$	*Real-Time Reg-Down Revenue*— The Real-Time Reg-Down revenue for QSE q calculated for Resource r for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
$\text{RTRRREV}_{q, r}$	$	*Real-Time Responsive Reserve Revenue*— The Real-Time RRS revenue for QSE q calculated for Resource r for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
$\text{RTNSREV}_{q, r}$	$	*Real-Time Non-Spin Revenue*— The Real-Time Non-Spin revenue for QSE q calculated for Resource r for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
$\text{RTECRREV}_{q, r}$	$	*Real-Time ERCOT Contingency Reserve Service Revenue*— The Real-Time ECRS revenue for QSE q calculated for Resource r for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.

q	none	A QSE.
r	none	A Switchable Generation Resource.
d	none	An Operating Day containing the RUC instruction to the SWGR.
i	none	A 15-minute Settlement Interval within the hour of an Operating Day during which the SWGR is instructed by ERCOT.
s	none	An ERCOT area start that is eligible to have its costs included in the Switchable Generation Cost Guarantee.
rc	none	A Resource Category.
p	none	A Resource Node Settlement Point.

(2) The total compensation to each QSE for the Switchable Generation Make-Whole Payment for a given hour in the Operating Day is calculated as follows:

$$\mathbf{SWMWAMTQSETOT}_{q} = \sum_{r} \mathbf{SWMWAMT}_{q,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
SWMWAMTQSETOT $_{q}$	$	*Switchable Generation Make-Whole Payment per QSE*—The total Switchable Generation Make-Whole Payment to the QSE *q*, for the hour.
SWMWAMT $_{q,\,r}$	$	*Switchable Generation Make-Whole Payment*—The Switchable Generation Make-Whole Payment to the QSE *q,* for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A Switchable Generation Resource.

6.6.12.2 Switchable Generation Make-Whole Charge

(1) The total cost for Switchable Generation Make-Whole Payments associated with SWGRs that switch to the ERCOT Control Area from a non-ERCOT Control Area pursuant to an ERCOT RUC instruction for an actual or anticipated EEA condition is allocated to QSEs representing Load based on HLRS. The Switchable Generation Make-Whole Charge for a given hour is calculated as follows:

$$\mathbf{LASWMWAMT}_{q} = (-1) * \mathbf{SWMWAMTTOT} * \mathbf{HLRS}_{q}$$

Where:

$$\text{SWMWAMTTOT} = \sum_{q} \text{SWMWAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$LASWMWAMT_q$	$	*Load Allocated Switchable Generation Make-Whole Charge Amount–* The allocated charge to QSE *q* for Switchable Generation Make-Whole Payments.
SWMWAMTTOT	$	*Switchable Generation Make-Whole Payment Total*—The total Switchable Generation Make-Whole Payments to all QSEs for the hour.
$SWMWAMTQSETOT_q$	$	*Switchable Generation Make-Whole Payment per QSE* —The total Switchable Generation Make-Whole Payment to the QSE *q* for the hour.
$HLRS_q$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour.* See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
q	none	A QSE.

6.6.12.3 Miscellaneous Invoice for Switchable Generation Make-Whole Payments and Charges

(1) All approved disputes shall be settled as described in Section 9.14.2, Notice of Dispute.

(2) ERCOT shall issue a miscellaneous Invoice to a QSE for Switchable Generation Make-Whole Payments as described in Section 6.6.12.1, Switchable Generation Make-Whole Payment.

(3) ERCOT shall issue a miscellaneous Invoice to the QSE representing Load based on the HLRS as described in Section 6.6.12.2, Switchable Generation Make-Whole Charge.

(4) ERCOT shall issue a Market Notice in conjunction with the issuance of the miscellaneous Invoice.

6.6.13 Wholesale Storage Load Reconciliation for ESRs Operating in a Private Microgrid Island

(1) A QSE representing an ESR operating in a Private Microgrid Island (PMI) configuration shall, within 96 hours of the end of such operations, submit a Settlement and billing dispute notifying ERCOT of the date and time that PMI operation began and ended. The QSE shall also notify the interconnecting Transmission and/or Distribution Service Provider(s) (TDSP(s)) of the time and date the PMI configuration began and ended within 96 hours of the end of such operations. Following the submission of such a dispute, ERCOT shall use the outflow quantities recorded by the ERCOT-Polled Settlement (EPS) Meter measuring the ESR's gross output net of any internal telemetered auxiliary Load, combined with any telemetered integrated auxiliary Load to determine the amount of Load served by the Resource during the period of PMI operation. ERCOT shall then determine the minimum whole number of Operating Days including and successively preceding the beginning of PMI operation for which the cumulative amount of WSL consumed on those Operating Days would equal or exceed the amount of Load served by the Resource during the period of PMI operation. ERCOT shall grant the

dispute and recharacterize all WSL previously settled on each such Operating Day as non-WSL. The adjustment to Settlements based on the recharacterization of WSL will be included in the RTM Final Settlement and/or RTM True-Up Settlement for each Operating Day.

6.6.14 Firm Fuel Supply Service Capability

6.6.14.1 Firm Fuel Supply Service Fuel Replacement Costs Recovery

(1) If ERCOT approves a Firm Fuel Supply Service Resource (FFSSR) to switch to consume the reserved fuel, ERCOT shall pay the QSE representing the FFSSR for the replacement of burned fuel, if the QSE has:

(a) Complied with the Firm Fuel Supply Service (FFSS) instruction to switch to the reserved fuel;

(b) Submitted a Settlement and billing dispute consistent with the dispute process described in Section 9.14, Settlement and Billing Dispute Process;

(c) Submitted the following within 90 days of the issuance of a Real-Time Market (RTM) Initial Statement for the Operating Day on which the FFSS instruction was issued:

(i) An attestation signed by an officer or executive with authority to bind the QSE stating that the information contained in the dispute is accurate;

(ii) For each deployment of FFSS, the quantity of total fuel consumed for the hours in each instance when FFSS was deployed;

(iii) For thermal units, the input-output equation or other documentation that allows for verification of fuel consumption for the hours when FFSS was deployed;

(iv) The dollar amount and quantity of fuel purchased to replace the consumed fuel;

(v) Sufficient documentation to support the QSE’s determination of the amount and cost of replaced fuel; and

(vi) Any other technical documentation within the possession of the QSE or Resource Entity which ERCOT finds reasonably necessary to verify paragraphs (i) through (v) above. Any additional request from ERCOT for documentation or clarification of previously submitted documentation must be honored within 15 Business Days.

(2) The Firm Fuel Supply Service Fuel Replacement Cost shall only represent the replacement fuel costs not recovered during the FFSS deployment period through Day-

Ahead energy sales and Real-Time energy imbalance settlement revenues related to the Resource with the FFSS award.

(3) ERCOT shall allocate any approved fuel replacement costs to the hours of the corresponding FFSS deployment period when the fuel was consumed following ERCOT's approval to switch to utilize the awarded FFSS.

6.6.14.2 Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery

(1) ERCOT shall pay an Hourly Standby Fee to a QSE representing an FFSSR. This standby fee is determined through a competitive bidding process, with an adjustment for reliability based on an Hourly Rolling Equivalent Availability Factor greater than or equal to 90% of the awarded FFSS capability.

(2) The FFSSR will be considered available when calculating the Firm Fuel Supply Service Hourly Rolling Equivalent Availability Factor during any successful FFSS deployment and during the period defined in the FFSS request for proposal (RFP) to restore FFSS capability following the instruction from ERCOT. In the event ERCOT does not issue an instruction or approval to restore FFSS capability, the FFSSR shall be considered to be available.

(3) The FFSS Hourly Standby Fee is subject to reduction and claw-back provisions as described in Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, and Decertification.

(4) ERCOT shall pay an FFSS payment to each QSE for each FFSSR. The FFSS payment for each hour of November 15, through March 15, during the FFSS obligation is calculated as follows:

$$\mathbf{FFSSAMT}_{q,r} = (-1) * (\mathbf{FFSSSBF}_{q,r} + \mathbf{FFSSFRC}_{q,r})$$

Where:

$$\text{FFSSSBF}_{q,r} = \text{FFSSPR}_{q,r} * \text{FFSSCRF}_{q,r} * \text{FFSSARF}_{q,r} * (1 - \text{FFSSDRP})$$

And:

FFSS Capacity Reduction Factor

If ($\text{FFSSTCAP}_{q,r} \geq \text{FFSSACAP}_{q,r}$)

Then: $\text{FFSSCRF}_{q,r} = 1$

Otherwise: $\text{FFSSCRF}_{q,r} = \text{Max}(0, 1 - 2 * (\text{FFSSACAP}_{q,r} - \text{FFSSTCAP}_{q,r}) / \text{FFSSACAP}_{q,r})$

FFSS Availability Reduction Factor

If ($\text{FFSSHREAF}_{q,\,r} \geq 0.90$)

Then: $\text{FFSSARF}_{q,\,r} = 1$

Otherwise: $\text{FFSSARF}_{q,\,r} = \text{Max}\,(0,\ 1 - (0.90 - \text{FFSSHREAF}_{q,\,r}) * 2)$

FFSS Hourly Rolling Equivalent Availability Factor

If the FFSSR is a Combined Cycle Resource:

Then:

$$\text{FFSSHREAF}_{q,\,train} = [\textstyle\sum_{hr=h-1451}^{h} \max_{train,\,hr}\,(\max(\text{FFSEDFLAG}_{q,\,train,\,hr},\ \text{FFSSAFLAG}_{q,\,ccgr,\,hr}) * (\min(\text{HSL}_{q,\,ccgr,\,hr},\ \text{FFSSACAP}_{q,\,train}))))] \,/\, \textstyle\sum_{hr=h-1451}^{h}(\text{FFSSACAP}_{q,\,train})$$

Otherwise:

$$\text{FFSSHREAF}_{q,\,r} = \textstyle\sum_{hr=h-1451}^{h}(\max(\text{FFSEDFLAG}_{q,\,r,\,hr},\ \text{FFSSAFLAG}_{q,\,r,\,hr}) * (\min(\text{HSL}_{q,\,r,\,hr},\ \text{FFSSACAP}_{q,\,r}))) \,/\, \textstyle\sum_{hr=h-1451}^{h}(\text{FFSSACAP}_{q,\,r})$$

Availability for a Combined Cycle Train will be determined pursuant to terms set forth in the RFP but no more than once per hour.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{FFSSAMT}_{q,\,r}$	\$	*Firm Fuel Supply Service Amount per QSE per Resource by hour*—The payment to QSE *q* for the FFSS provided by Resource *r*, for the hour, calculated each hour of November 15 through March 15 during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSPR}_{q,\,r}$	\$ per hour	*Firm Fuel Supply Service Price per QSE per Resource*—The standby price of FFSSR *r* represented by QSE *q*, as specified in the FFSS award. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSCRF}_{q,\,r}$	none	*Firm Fuel Supply Service Capacity Reduction Factor per QSE per Resource by hour*—The capacity reduction factor for the FFSSR *r*, represented by QSE *q*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{HSL}_{q,\,r,\,hi}$	MW	*High Sustained Limit*—The HSL of a Generation Resource *r* represented by QSE *q* as submitted in the COP, for the hour *h*. Where for a combined cycle Resource *r* is a Combined Cycle Generation Resource.
$\text{FFSSFRC}_{q,\,r}$	\$ per hour	*Firm Fuel Supply Service Fuel Replacement Cost*—The fuel costs and fees to replace the burned fuel, not recovered during the FFSS deployment period, for FFSSR *r* represented by QSE *q* for each FFSS instructed hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSDRP}_{q,\,r,\,h}$	none	*Firm Fuel Supply Service Deployment Reduction Percentage*—The percentage of the Firm Fuel Supply Service Standby Fee subject to clawback per paragraphs (5) through (12) of Section 8.1.1.2.1.6 for the QSE *q*, for the Resource *r*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition
$\text{FFSSSBF}_{q,\,r}$	$	*Firm Fuel Supply Service Standby Fee per QSE per Resource by hour*—The standby fee to QSE *q* for the FFSS provided by FFSSR *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSTCAP}_{q,\,r}$	MW	*Firm Fuel Supply Service Testing Capacity per QSE per Resource*—The tested capacity of FFSSR *r*, represented by QSE *q*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSACAP}_{q,\,r}$	MW	*Firm Fuel Supply Service Awarded Capacity per QSE per Resource*—The awarded FFSS capacity of FFSSR *r*, represented by QSE *q* as specified in the FFSS award, applicable to each hour of November 15 through March 15 during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSARF}_{q,\,r}$	none	*Firm Fuel Supply Service Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor of FFSSR *r* represented by QSE *q* for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSHREAF}_{q,\,r}$	none	*Firm Fuel Supply Service Hourly Rolling Equivalent Availability Factor per QSE per Resource by hour*—The equivalent availability factor of the FFSSR *r* represented by QSE *q* over 1,452 hours, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{FFSSAFLAG}_{q,\,r,\,hr}$	none	*Firm Fuel Supply Service Availability Flag per QSE per Resource by hour*—The flag of the availability of FFSSR *r* represented by QSE *q*, 1 for available and 0 for unavailable, for the hour. The availability flag shall be determined based on FFSSR availability for the current operating hour and the previous 1,451 hours of November 15 through March 15 during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{FFSEDFLAG}_{q,\,r,\,hr}$	none	*Firm Fuel Supply Event Deployment Flag per QSE per Resource by hour*—The flag of successful FFSS deployment of the FFSSR *r* including hours in the period defined in the RFP following the instruction from ERCOT to restore FFSS capability represented by QSE *q*, 1 for available and 0 for unavailable, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An FFSSR.
hr	none	The index of a given hour and the previous 1,451 hours counted only during each hour of November 15 through March 15 during the awarded FFSS obligation period, or during the period as defined in the FFSS RFP.
h	none	The Operating Hour.
train	none	A Combined Cycle Train.
ccgr	none	A Combined Cycle Generation Resource within the Combined Cycle Train.

(5) The total of the payments to each QSE for all FFSSRs represented by this QSE for a given hour is calculated as follows:

$$\mathbf{FFSSAMTQSETOT}_{\boldsymbol{q}} \quad = \quad \sum_{r} \mathbf{FFSSAMT}_{\boldsymbol{q,\,r}}$$

The above variables are defined as follows:

Variable	Unit	Definition
FFSSAMTQSETOT_{q}	$	*Firm Fuel Supply Service Amount QSE Total per QSE*—The total of the payments to QSE *q* for FFSS provided by all the FFSS Resources represented by this QSE for the hour.
$\text{FFSSAMT}_{q,\,r}$	$	*Firm Fuel Supply Service Amount per QSE per Resource*—The payment to QSE *q* for the FFSS provided by Resource *r*, for the hour, calculated each hour of November 15 through March 15 during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	An FFSSR.

6.6.14.3 Firm Fuel Supply Service Capacity Charge

(1) ERCOT shall allocate the total FFSS capacity and fuel replacement payment to the QSEs representing Loads based on an hourly LRS. The resulting charge to each QSE for a given hour is calculated as follows:

$$\textbf{LAFFSSAMT}_{q} \quad = \quad \textbf{(-1) * FFSSAMTTOT * HLRS}_{q}$$

Where:

$$\text{FFSSAMTTOT} \quad = \quad \sum_{q} \text{FFSSAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LAFFSSAMT_{q}	$	*Load-Allocated Firm Fuel Supply Service Amount per QSE*—The charge allocated to QSE *q* for the FFSS, for the hour.
FFSSAMTQSETOT_{q}	$	*Firm Fuel Supply Service Amount QSE Total per QSE*—The total of the payments to QSE *q* for FFSS provided by all the FFSSRs represented by this QSE for the hour.
FFSSAMTTOT	$	*Firm Fuel Supply Service Amount QSE Total ERCOT-Wide*—The total of the payments to all QSEs for FFSS for the hour.
HLRS_{q}	none	The hourly LRS calculated for QSE *q* for the hour. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
q	none	A QSE.

6.7 Real-Time Settlement Calculations for the Ancillary Services

6.7.1 Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Services Market (SASM) or Reconfiguration Supplemental Ancillary Services Market (RSASM)

(1) If a Supplemental Ancillary Services Market (SASM) or a Reconfiguration Supplemental Ancillary Services Market (RSASM) is executed for one or more Operating Hours for any reason, ERCOT shall pay Qualified Scheduling Entities (QSEs) for their Ancillary Service Offers cleared in the SASM or RSASM, based on the Market Clearing Price for

Capacity (MCPC) for that SASM or RSASM and that service. By service and by SASM or RSASM, the payment to each QSE for a given Operating Hour is calculated as follows:

(a) For Regulation Up (Reg-Up), if applicable:

$$\mathbf{RTPCRUAMT}_{q,\,m} = \mathbf{(-1) * MCPCRU}_{m} \mathbf{\; * \; RTPCRU}_{q,\,m}$$

Where:

$$\text{RTPCRU}_{q,\,m} = \sum_{r} \text{PCRUR}_{q,\,r,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
RTPCRUAMT $_{q,\,m}$	$	*Procured Capacity for Reg-Up Amount by QSE by market*—The payment to QSE *q* for the Ancillary Service Offers cleared in the market *m* to provide Reg-Up, for the hour.
MCPCRU $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by market*—The MCPC for Reg-Up from the market *m*, for the hour.
RTPCRU $_{q,\,m}$	MW	*Procured Capacity for Reg-Up by QSE by market*—The portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Up, for the hour.
PCRUR $_{q,\,r,\,m}$	MW	*Procured Capacity for Reg-Up from Resource per Resource per QSE by market*—The Reg-Up capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
m	none	An Ancillary Service market (SASM or RSASM).
q	none	A QSE.
r	none	A Generation Resource.

(b) For Regulation Down (Reg-Down), if applicable:

$$\mathbf{RTPCRDAMT}_{q,\,m} = \mathbf{(-1) * MCPCRD}_{m} \mathbf{\; * \; RTPCRD}_{q,\,m}$$

Where:

$$\text{RTPCRD}_{q,\,m} = \sum_{r} \text{PCRDR}_{r,\,q,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
RTPCRDAMT $_{q,\,m}$	$	*Procured Capacity for Reg-Down Amount by QSE by market*—The payment to QSE *q* for the Ancillary Service Offers cleared in the market *m* to provide Reg-Down, for the hour.
MCPCRD $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by market*—The MCPC for Reg-Down from the market *m*, for the hour.

Variable	Unit	Description
$\text{RTPCRD}_{q,\ m}$	MW	*Procured Capacity for Reg-Down by QSE by market*—The portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Down, for the hour.
$\text{PCRDR}_{r,\ q,\ m}$	MW	*Procured Capacity for Reg-Down from Resource per Resource per QSE by market*—The Reg-Down capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
m	none	An Ancillary Service market (SASM or RSASM).
q	none	A QSE.
r	none	A Generation Resource.

(c) For Responsive Reserve (RRS), if applicable:

$$\textbf{RTPCRRAMT}_{q,\ m} = (-1) * \textbf{MCPCRR}_{m} * \textbf{RTPCRR}_{q,\ m}$$

Where:

$$\text{RTPCRR}_{q,\ m} = \sum_{r} \text{PCRRR}_{q,\ r,\ m}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTPCRRAMT}_{q,\ m}$	\$	*Procured Capacity for Responsive Reserve Amount by QSE by market*—The payment to QSE *q* for the Ancillary Service Offer cleared in the market *m* to provide RRS, for the hour.
MCPCRR_{m}	\$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve by market*—The MCPC for RRS from the market *m*, for the hour.
$\text{RTPCRR}_{q,\ m}$	MW	*Procured Capacity for Responsive Reserve by QSE by market*—The portion of QSE *q* Ancillary Service Offers cleared in the market *m* to provide RRS, for the hour.
$\text{PCRRR}_{q,r,\ m}$	MW	*Procured Capacity for Responsive Reserve from Resource per Resource per QSE by market*—The RRS capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
m	none	An Ancillary Service market (SASM or RSASM).
q	none	A QSE.
r	none	A Generation Resource.

(d) For Non-Spinning Reserve (Non-Spin), if applicable:

$$\textbf{RTPCNSAMT}_{q,\ m} = (-1) * \textbf{MCPCNS}_{m} * \textbf{RTPCNS}_{q,\ m}$$

Where:

$$\text{RTPCNS}_{q,\,m} = \sum_{r} \text{PCNSR}_{q,\,r,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTPCNSAMT}_{q,\,m}$	$	*Procured Capacity for Non-Spin Amount by QSE by market*—The payment to QSE *q* for Ancillary Service Offer cleared in the market *m* to provide Non-Spin, for the hour.
MCPCNS_{m}	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by market*—The MCPC for Non-Spin from the market *m*, for the hour.
$\text{RTPCNS}_{q,\,m}$	MW	*Procured Capacity for Non-Spin by QSE by market*—The portion of QSE *q*'s Ancillary Service Offer cleared in the market *m* to provide Non-Spin, for the hour.
$\text{PCNSR}_{q,r,\,m}$	MW	*Procured Capacity for Non-Spin from Resource per Resource per QSE by market*—The Non-Spin capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
m	none	An Ancillary Service market (SASM or RSASM).
q	none	A QSE.
r	none	A Generation Resource.

[NPRR863: Insert paragraph (e) below upon system implementation:]

(e) For ERCOT Contingency Reserve Service (ECRS), if applicable:

$$\mathbf{RTPCECRAMT}_{q,\,m} = \mathbf{(-1) * MCPCECR}_{m} \mathbf{\; * \; RTPCECR}_{q,\,m}$$

Where:

$$\text{RTPCECR}_{q,\,m} = \sum_{r} \text{PCECRR}_{q,\,r,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTPCECRAMT}_{q,\,m}$	$	*Procured Capacity for ERCOT Contingency Reserve Service Amount by QSE by market*—The payment to QSE *q* for the Ancillary Service Offer cleared in the market *m* to provide ECRS, for the hour.
MCPCECR_{m}	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service by market*—The MCPC for ECRS from the market *m*, for the hour.
$\text{RTPCECR}_{q,\,m}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service by QSE by market*—The portion of QSE *q* Ancillary Service Offers cleared in the market *m* to provide ECRS, for the hour.
$\text{PCECRR}_{q,\,r,\,m}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service from Resource per Resource per QSE by market*—The ECRS capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

m	none	An Ancillary Service market (SASM or RSASM).
q	none	A QSE.
r	none	A Generation Resource.

[NPRR1010: Delete Section 6.7.1 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.7.2 Payments for Ancillary Service Capacity Assigned in Real-Time Operations

(1) Resources that have received an Ancillary Service Assignment during a Watch as set forth in paragraph (4) of Section 6.5.9.3.3, Watch, may receive a payment for the un-deployed quantity of Ancillary Service reserves associated with each hour of the Ancillary Service Assignment if the Resource's dispatch is limited by the Ancillary Service Assignment. ERCOT will provide a Verbal Dispatch Instruction (VDI) to every QSE with an On-Line Resource with an Ancillary Service Assignment. The QSE must file a Settlement dispute to be considered for the Real-Time assigned Ancillary Services payment amount. The payment to each QSE and Resource for the 15-minute Settlement Interval in which the Resource received an Ancillary Service Assignment will be made when the Resource is dispatched to its High Ancillary Service Limit (HASL) in at least one Security-Constrained Economic Dispatch (SCED) interval in the 15-minute Settlement Interval. The payment shall be calculated as follows.

(a) For Reg-Up, if applicable:

$$\mathbf{RTAURUAMT}_{q,r,p,i} = \mathbf{(-1) * 1/4 * RTAURUR}_{q,r,p} \mathbf{* (RTSPP}_{p,i} \mathbf{- RTRSVPOR - RTRDP)}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTAURUAMT $_{q,r,p,i}$	$	*Real-Time Assigned Un-Deployed Regulation Up Payment Amount per Resource per QSE*— The payment to QSE *q* for a Real-Time un-deployed Reg-Up Ancillary Service Assignment to Resource *r* at the Settlement Point *p* for the 15-minute Settlement Interval *i*.

Variable	Unit	Description
$RTAURUR_{q, r, p}$	MW	*Real-Time Assigned Un-Deployed Regulation Up Quantity per Resource per QSE*—The quantity of un-deployed Reg-Up assigned under a Watch to a QSE *q* for Resource *r* at Settlement Point *p* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RTSPP_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$RTORPA_{y}$	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
$RTORDPA_{y}$	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
q	none	A QSE.
r	none	A Generation Resource that was allocated Reg-Up Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated Reg-Up Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.
y	none	A SCED interval in the 15-minute Settlement Interval.

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

(a) For Reg-Up, if applicable:

$$\mathbf{RTAURUAMTQSETOT}_{q} = \sum_{r} \mathbf{RTAURUAMT}_{q\, r, p, i}$$

Where:

$$RTAURUAMT_{q, r, p, i} = (-1) * 1/4 * RTAURUR_{q, r, p} * (RTSPP_{p, i} - RTRSVPOR - RTRDP)$$

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$\text{RTAURUAMTQSETOT}_{q}$	$	*Real-Time Assigned Un-Deployed Regulation Up Payment Amount per QSE* - The payment to QSE *q* for a Real-Time un-deployed Reg-Up Ancillary Service Assignment.
$\text{RTAURUAMT}_{q, r, p, i}$	$	*Real-Time Assigned Un-Deployed Regulation Up Payment Amount per Resource per QSE*— The payment to QSE *q* for a Real-Time un-deployed Reg-Up Ancillary Service Assignment to Resource *r* at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
$\text{RTAURUR}_{q, r, p}$	MW	*Real-Time Assigned Un-Deployed Regulation Up Quantity per Resource per QSE*—The quantity of un-deployed Reg-Up assigned under a Watch to a QSE *q* for Resource *r* at Settlement Point *p* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTSPP}_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
RTORPA_{y}	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTORDPA_{y}	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
q	none	A QSE.
r	none	A Generation Resource that was allocated Reg-Up Ancillary Service Assignment by the QSE.

p	none	A Settlement Point for the Resource Node that was allocated Reg-Up Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.
y	none	A SCED interval in the 15-minute Settlement Interval.

(b) For RRS Service, if applicable:

$$\mathbf{RTAURRAMT}_{q,\,r,\,p,\,i} = \mathbf{(-1) * 1/4 * RTAURRR}_{q,\,r,\,p} \mathbf{* (RTSPP}_{p,\,i} \mathbf{- RTRSVPOR - RTRDP)}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTAURRAMT $_{q,\,r,\,p\ \ i}$	$	*Real-Time Assigned Un-Deployed Responsive Reserve Payment Amount per Resource per QSE* - The payment to QSE *q* for a Real-Time un-deployed RRS Ancillary Service Assignment to Resource *r* at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
RTAURRR $_{q,\,r,\,p}$	MW	*Real-Time Assigned Un-Deployed Responsive Reserve Quantity per Resource per QSE* - The quantity of un-deployed RRS assigned under a Watch to a QSE *q* for Resource *r* at the Settlement Point *p* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTSPP $_{p,\,i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*— The Real-Time Settlement Point Price at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the 15-minute Settlement Interval.

Variable	Unit	Description
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
q	none	A QSE.
r	none	A Generation Resource that was allocated RRS Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated RRS Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.
y	none	A SCED interval in the 15-minute Settlement Interval.

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

(b) For RRS, if applicable:

$$\textbf{RTAURRAMTQSETOT}_{q} = \sum_{r} \textbf{RTAURRAMT}_{q\, r, p, i}$$

Where:

$$\text{RTAURRAMT}_{q, r, p, i} = (-1) * 1/4 * \text{RTAURRR}_{q, r, p} * (\text{RTSPP}_{p, i} - \text{RTRSVPOR})$$

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTAURRAMTQSETOT}_{q}$	\$	*Real-Time Assigned Un-Deployed Responsive Reserve Payment Amount per QSE* - The payment to QSE *q* for a Real-Time un-deployed RRS Ancillary Service Assignment.
$\text{RTAURRAMT}_{q, r, p, i}$	\$	*Real-Time Assigned Un-Deployed Responsive Reserve Payment Amount per Resource per QSE* - The payment to QSE *q* for a Real-Time un-deployed RRS Ancillary Service Assignment to Resource *r* at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
$\text{RTAURRR}_{q, r, p}$	MW	*Real-Time Assigned Un-Deployed Responsive Reserve Quantity per Resource per QSE* - The quantity of un-deployed RRS assigned under a Watch to a QSE *q* for Resource *r* at the Settlement Point *p* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

$\text{RTSPP}_{p,\,i}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*— The Real-Time Settlement Point Price at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
q	none	A QSE.
r	none	A Generation Resource that was allocated RRS Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated RRS Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.
y	none	A SCED interval in the 15-minute Settlement Interval.

[NPRR863: Insert paragraph (c) below upon system implementation:]

(c) For ECRS, if applicable:

$$\textbf{RTAUECRAMTQSETOT}_{q} = \sum_{r} \textbf{RTAUECRAMT}_{q\,r,\,p,\,i}$$

Where:

$$\text{RTAUECRAMT}_{q\,r,\,p,\,i} = (-1) * 1/4 * \text{RTAUECRR}_{q,\,r,\,p} * (\text{RTSPP}_{p,\,i} - \text{RTRSVPOR} - \text{RTRDP})$$

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTAUECRAMTQSETOT}_q$	$	*Real-Time Assigned Un-Deployed ERCOT Contingency Reserve Service Payment Amount per QSE* - The payment to QSE *q* for a Real-Time un-deployed ECRS Ancillary Service Assignment.
$\text{RTAUECRAMT}_{q, r, p, i}$	$	*Real-Time Assigned Un-Deployed ERCOT Contingency Reserve Service Payment Amount per Resource per QSE* - The payment to QSE *q* for a Real-Time un-deployed ECRS Ancillary Service Assignment to Resource *r* at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
$\text{RTAUECRR}_{q, r, p}$	MW	*Real-Time Assigned Un-Deployed ERCOT Contingency Reserve Service Quantity per Resource per QSE* - The quantity of un-deployed ECRS assigned under a Watch to a QSE *q* for Resource *r* at the Settlement Point *p* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTSPP}_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*— The Real-Time Settlement Point Price at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
TLMP_y	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RNWF_y	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
RTORPA_y	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTORDPA_y	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
q	none	A QSE.
r	none	A Generation Resource that was allocated ECRS Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated ECRS Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.
y	none	A SCED interval in the 15-minute Settlement Interval.

[NPRR1010: Delete Section 6.7.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.7.2.1 Charges for Infeasible Ancillary Service Capacity Due to Transmission Constraints

(1) A charge to each QSE with Ancillary Service Supply Responsibility that is deemed infeasible by ERCOT as a result of a transmission constraints, whether or not a SASM is executed, is calculated as follows:

(a) For Reg-Up, if applicable:

$$\mathbf{RUINFQAMT}_{q} = \mathbf{MCPCRU}_{DAM} * \mathbf{RUINFQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RUINFQAMT $_{q}$	$	*Reg-Up Infeasible Quantity Amount per QSE*— The charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
MCPCRU $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up in DAM*—The DAM MCPC for Reg-Up, for the hour.
RUINFQ $_{q}$	MW	*Reg-Up Infeasible Quantity per QSE* —QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
q	none	A QSE.

(b) For Reg-Down, if applicable:

$$\mathbf{RDINFQAMT}_{q} = \mathbf{MCPCRD}_{DAM} * \mathbf{RDINFQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RDINFQAMT $_{q}$	$	*Reg-Down Infeasible Quantity Amount per QSE*— The charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
MCPCRD $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down in DAM*—The DAM MCPC for Reg-Down, for the hour.
RDINFQ $_{q}$	MW	*Reg-Down Infeasible Quantity per QSE* —QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
q	none	A QSE.

(c) For RRS, if applicable:

$$\mathbf{RRINFQAMT}_{q} = \mathbf{MCPCRR}_{DAM} * \mathbf{RRINFQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RRINFQAMT_{q}	\$	*Responsive Reserve Infeasible Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for RRS, for the hour.
MCPCRR_{DAM}	\$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for RRS, for the hour.
RRINFQ_{q}	MW	*Responsive Reserve Infeasible Quantity per QSE* —QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for RRS, for the hour.
q	none	A QSE.

(d) For Non-Spin, if applicable:

$$\mathbf{NSINFQAMT}_{q} = \mathbf{MCPCNS}_{DAM} * \mathbf{NSINFQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
NSINFQAMT_{q}	\$	*Non-Spin Infeasible Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
MCPCNS_{DAM}	\$/MW per hour	*Market Clearing Price for Capacity for Non-Spin in DAM*—The DAM MCPC for Non-Spin, for the hour.
NSINFQ_{q}	MW	*Non-Spin Infeasible Quantity per QSE*—QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
q	none	A QSE.

[NPRR863: Insert paragraph (e) below upon system implementation:]

(e) For ECRS, if applicable:

$$\mathbf{ECRINFQAMT}_{q} = \mathbf{MCPCECR}_{DAM} * \mathbf{ECRINFQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
ECRINFQAMT_{q}	\$	*ERCOT Contingency Reserve Service Infeasible Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with infeasible

		deployment of Ancillary Service Supply Responsibilities for ECRS, for the hour.
MCPCECR $_{DAM}$	\$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service in DAM*—The DAM MCPC for ECRS, for the hour.
ECRINFQ $_{q}$	MW	*ERCOT Contingency Reserve Service Infeasible Quantity per QSE* —QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for ECRS, for the hour.
q	none	A QSE.

[NPRR1010: Delete Section 6.7.2.1 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

[NPRR841 and NPRR863: Insert applicable portions of Section 6.7.2.2 below upon system implementation:]

6.7.2.2 Real-Time Adjustments to Day-Ahead Make Whole Payments due to Ancillary Services Infeasibility Charges

(1) ERCOT shall pay the QSE for which ERCOT calculates a charge for infeasible Ancillary Service capacity due to transmission constraints a Real-Time Day-Ahead Make-Whole Payment for an eligible Resource for each Operating Hour in a DAM commitment period.

(2) The guaranteed cost, energy revenue, and Ancillary Service revenue calculated for each Combined Cycle Generation Resource are each summed for the Combined Cycle Train, and the Real-Time Day-Ahead Make-Whole Amount is calculated for the Combined Cycle Train.

$$\textbf{RTDAMWAMT}_{q,r,p,h} = \textbf{(-1)*Max(0, DAMGCOST}_{q,r,p} + \sum_{h} \textbf{DAEREV}_{q,r,p,h} + \sum_{h} \textbf{INFQAR}_{q,r,p,h} + \sum_{h} \textbf{DAASREV}_{q,r,h} + \sum_{h} \textbf{DAMWAMT}_{q,r,p,h}\textbf{) * ASINFQR}_{q,r,p,h} / \sum_{h} \textbf{ASINFQR}_{q,r,p,h}$$

Where:

$$\text{INFQAR}_{q,r,p,h} = \text{RUINFQAR}_{q,r,p,h} + \text{RDINFQAR}_{q,r,p,h} + \text{RRINFQAR}_{q,r,p,h} + \text{NSINFQAR}_{q,r,p,h} + \text{ECRINFQAR}_{q,r,p,h}$$

And,

$$\text{RUINFQAR}_{q,\ r,\ p,\ h} = \text{MCPCRU}_{DAM} * \text{RUINFQR}_{q,\ r,\ p,\ h}$$

$$\text{RDINFQAR}_{q,\ r,\ p,\ h} = \text{MCPCRD}_{DAM} * \text{RDINFQR}_{q,\ r,\ p,\ h}$$

$$\text{RRINFQAR}_{q,\ r,\ p,\ h} = \text{MCPCRR}_{DAM} * \text{RRINFQR}_{q,\ r,\ p,\ h}$$

$$\text{NSINFQAR}_{q,\ r,\ p,\ h} = \text{MCPCNS}_{DAM} * \text{NSINFQR}_{q,\ r,\ p,\ h}$$

$$\text{ECRINFQAR}_{q,\ r,\ p,\ h} = \text{MCPCECR}_{DAM} * \text{ECRINFQR}_{q,\ r,\ p,\ h}$$

$$\begin{aligned}\text{ASINFQR}_{q,\ r,\ p,\ h} = {} & \text{RUINFQR}_{q,\ r,\ p,\ h} + \text{RDINFQR}_{q,\ r,\ p,\ h} + \text{RRINFQR}_{q,\ r,\ p,\ h} + \\ & \text{NSINFQR}_{q,\ r,\ p,\ h} + \text{ECRINFQR}_{q,\ r,\ p,\ h}\end{aligned}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTDAMWAMT $_{q,\ r,\ p,\ h}$	$	*Real-Time Day-Ahead Make-Whole Payment Amount per QSE per Resource per Settlement Point per hour* —The Real-Time calculated payment to QSE *q* to make-whole the Startup Cost and energy costs of Resource *r* committed in the DAM at Resource Node *p* for the hour *h*. When a Combined Cycle Generation Resource is committed in the DAM, payment is made to the Combined Cycle Train for the DAM-committed Combined Cycle Generation Resource.
DAMGCOST $_{q,\ r,\ p}$	$	*Day-Ahead Market Guaranteed Amount per QSE per Resource per Settlement Point* — The sum of the Startup Cost and the operating energy costs of the DAM-committed Resource *r* at Resource Node *p* represented by QSE *q*, for the DAM-commitment period. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DAEREV $_{q,\ r,\ p,\ h}$	$	*Day-Ahead Energy Revenue per QSE per Resource per Settlement Point per hour* —The revenue received in the DAM for Resource *r* at Resource Node *p* represented by QSE *q*, based on the DAM Settlement Point Price, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
INFQAR $_{q,\ r,\ p,\ h}$	$	*Infeasible Quantity Amount per QSE per Resource per Settlement Point per hour* —The dollar amount to QSE *q* for Resource *r* of its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibility, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DAMWAMT $_{q,\ r,\ p,\ h}$	$	*Day-Ahead Make-Whole Payment per QSE per Resource per Settlement Point per hour* —The payment to QSE *q* to make-whole the Startup Cost and energy cost of Resource *r* committed in the DAM at Resource Node *p* for the hour *h*. When a Combined Cycle Generation Resource is committed

		in the DAM, payment is made to the Combined Cycle Train for the DAM-committed Combined Cycle Generation Resource.
DAASREV $_{q, r, h}$	$	*Day-Ahead Ancillary Service Revenue per QSE per Resource by hour*—The revenue received in the DAM for Resource *r* represented by QSE *q*, based on the MCPC for each Ancillary Service in the DAM, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RUINFQAR $_{q, r, p, h}$	$	*Reg-Up Infeasible Quantity Amount per QSE per Resource per Settlement Point per hour* — The dollar amount to QSE *q,* for Resource *r,* for its capacity associated with infeasible deployment of Ancillary Service Supply Responsibility for Reg-Up, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRU $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up in DAM*—The DAM MCPC for Reg-Up for the hour.
RDINFQAR $_{q, r, p, h}$	$	*Reg-Down Infeasible Quantity Amount per QSE per Resource per Settlement Point per hour* — The dollar amount to QSE *q,* for Resource *r,* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibility for Reg-Down, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRD $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down in DAM*—The DAM MCPC for Reg-Down for the hour.
RRINFQAR $_{q, r, p, h}$	$	*Responsive Reserve Infeasible Quantity Amount per QSE per Resource per Settlement Point per hour* — The dollar amount to QSE *q,* for Resource *r,* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibility for RRS, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRR $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for RRS for the hour.
NSINFQAR $_{q, r, p, h}$	$	*Non-Spin Infeasible Quantity Amount per QSE per Resource per Settlement Point per hour* — The dollar amount to QSE *q,* for Resource *r,* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibility for Non-Spin, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCNS $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin Service in DAM*—The DAM MCPC for Non-Spin for the hour.
ECRINFQAR $_{q, r, p, h}$	$	*ERCOT Contingency Reserve Service Infeasible Quantity Amount per QSE per Resource per Settlement Point per hour* — The dollar amount to QSE *q*, for Resource *r,* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibility for ECRS, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCECR $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service in DAM*—The DAM MCPC for ECRS for the hour.

$\text{ASINFQR}_{q, r, p, h}$	MW	*Ancillary Service Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RUINFQR}_{q, r, p, h}$	MW	*Reg-Up Infeasible Quantity per QSE per Resource per Settlement Point per hour* —The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for Reg-Up, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RDINFQR}_{q, r, p, h}$	MW	*Reg-Down Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for Reg-Down, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RRINFQR}_{q, r, p, h}$	MW	*Responsive Reserve Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for RRS, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{NSINFQR}_{q, r, p, h}$	MW	*Non-Spin Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for Non-Spin, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{ECRINFQR}_{q, r, p, h}$	MW	*ERCOT Contingency Reserve Service Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for ECRS, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
h	none	An hour in the DAM-commitment period.
q	none	A QSE.
r	none	A DAM-committed Generation Resource.
p	none	A Resource Node Settlement Point.

(3) The total Real-Time Day-Ahead Make-Whole Payments to each QSE for Generation Resources for a given hour is calculated as follows:

$$\mathbf{RTDAMWAMTQSETOT}_{q, h} = \sum_{r} \mathbf{RTDAMWAMT}_{q, r, p, h}$$

And,

$$\mathbf{RTDAMWAMTTOT}_{h} = \sum_{q} \mathbf{RTDAMWAMTQSETOT}_{q, h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RTDAMWAMTQSETOT}_{q,h}$	$	*Real-Time Day-Ahead Make-Whole Payment Amount per QSE per hour*—The Real-Time calculated payment to QSE *q* to make-whole the Startup Cost and energy costs of all Resources *r* committed in the DAM at Resource Node *p* for the hour *h*.
$\text{RTDAMWAMT}_{q,r,p,h}$	$	*Real-Time Day-Ahead Make-Whole Payment Amount per QSE per Resource per Settlement Point per hour* —The Real-Time calculated payment to QSE *q* to make-whole the Startup and energy costs of Resource *r* committed in the DAM at Resource Node *p* for the hour *h*. For a Combined Cycle Generation Resource is committed in the DAM, payment is made to the Combined Cycle Train for the DAM-committed Combined Cycle Generation Resource.
RTDAMWAMTTOT_{h}	$	*Real-Time Day-Ahead Make-Whole Payment Amount per hour*—The Real-Time calculated payment to all QSEs to make-whole the Startup and energy costs of all Resources *r* committed for the hour *h*.
h	none	An hour in the DAM-commitment period.
q	none	A QSE.
r	none	A DAM-committed Generation Resource.
p	none	A Resource Node Settlement Point.

(4) For each QSE for which ERCOT calculates a Real-Time DAM Make-Whole payment an adjustment for each Ancillary Service is computed as follows:

$$\text{RUMWINFA}_{q,h} = \sum_{r} \text{RTDAMWAMT}_{q,r,p,h} * \text{RUINFQR}_{q,r,p,h} / \text{ASINFQR}_{q,r,p,h}$$

$$\text{RDMWINFA}_{q,h} = \sum_{r} \text{RTDAMWAMT}_{q,r,p,h} * \text{RDINFQR}_{q,r,p,h} / \text{ASINFQR}_{q,r,p,h}$$

$$\text{RRMWINFA}_{q,h} = \sum_{r} \text{RTDAMWAMT}_{q,r,p,h} * \text{RRINFQR}_{q,r,p,h} / \text{ASINFQR}_{q,r,p,h}$$

$$\text{NSMWINFA}_{q,h} = \sum_{r} \text{RTDAMWAMT}_{q,r,p,h} * \text{NSINFQR}_{q,r,p,h} / \text{ASINFQR}_{q,r,p,h}$$

$$\text{ECRMWINFA}_{q,h} = \sum_{r} \text{RTDAMWAMT}_{q,r,p,h} * \text{ECRINFQR}_{q,r,p,h} / \text{ASINFQR}_{q,r,p,h}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RUMWINFA}_{q,h}$	$	*Regulation Up Make-Whole Infeasible Amount per QSE per hour*— The total Real-Time calculated payment to QSE *q,* for its contribution of Regulation Up Ancillary Service, to make-whole the Startup and energy costs of all Resources committed in the DAM for the hour *h*.
$\text{RDMWINFA}_{q,h}$	$	*Regulation Down Make-Whole Amount per QSE per hour* — The total Real-Time calculated payment to QSE *q,* for its contribution of Reg-Down, to make-whole the Startup and energy costs of all Resources committed in the DAM for the hour *h*.
$\text{RRMWINFA}_{q,h}$	$	*Responsive Reserve Make-Whole Infeasible Amount per QSE per hour* — The total Real-Time calculated payment to QSE *q,* for its contribution of

		RRS, to make-whole the Startup and energy costs of all Resources committed in the DAM for the hour *h*.
NSMWINFA $_{q,\,h}$	$	*Non-Spin Make-Whole Infeasible Amount per QSE per hour* — The total Real-Time calculated payment to QSE *q,* for its contribution of Non-Spin, to make-whole the Startup and energy costs of all Resources committed in the DAM for the hour *h*.
ECRMWINFA $_{q,\,h}$	$	*ERCOT Contingency Reserve Service Make-Whole Infeasible Amount per QSE per hour* — The total Real-Time calculated payment to QSE *q,* for its contribution of ECRS, to make-whole the Startup and energy costs of all Resources committed in the DAM for the hour *h*.
RTDAMWAMT $_{q,\,r,\,p,\,h}$	$	*Real-Time Day-Ahead Make-Whole Payment Amount per QSE per Resource per Settlement Point per hour* —The Real-Time calculated payment to QSE *q* to make-whole the Startup Cost and energy costs of Resource *r* committed in the DAM at Resource Node *p* for the hour *h*. When a Combined Cycle Generation Resource is committed in the DAM, payment is made to the Combined Cycle Train for the DAM-committed Combined Cycle Generation Resource.
RUINFQR $_{q,\,r,\,p,\,h}$	MW	*Reg-Up Infeasible Quantity per QSE per Resource per Settlement Point per hour* —The Resource *r total* capacity associated with infeasible Ancillary Service Supply Responsibility for Reg-Up, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RDINFQR $_{q,\,r,\,p,\,h}$	MW	*Reg-Down Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for Reg-Down, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RRINFQR $_{q,\,r,\,p,\,h}$	MW	*Responsive Reserve Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for RRS, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
NSINFQR $_{q,\,r,\,p,\,h}$	MW	*Non-Spin Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for Non-Spin, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
ECRINFQR $_{q,\,r,\,p,\,h}$	MW	*ERCOT Contingency Reserve Service Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility for ECRS, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
ASINFQR $_{q,\,r,\,p,\,h}$	MW	*Ancillary Service Infeasible Quantity per QSE per Resource per Settlement Point per hour* — The Resource *r* total capacity associated with infeasible Ancillary Service Supply Responsibility, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
h	none	An hour in the DAM-commitment period.
q	none	A QSE.
r	none	A DAM-committed Generation Resource.

p	none	A Resource Node Settlement Point.

[NPRR1010: Delete Section 6.7.2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.7.3 Charges for Ancillary Service Capacity Replaced Due to Failure to Provide

(1) A charge to each QSE that fails on its Ancillary Service Supply Responsibility, whether or not a SASM is executed due to its failure to supply, is calculated based on the greatest of the MCPC in the Day-Ahead Market (DAM) or any SASM for the same Operating Hour. Included in the failed quantity is the charge to each QSE that reduces its Ancillary Service Supply Responsibility by an RSASM, which is calculated based on the cleared MCPC associated with the RSASM. By service, the charge to each QSE for a given Operating Hour is calculated as follows:

(a) The total charge of failure on Ancillary Service Supply Responsibility for Reg-Up by QSE, if applicable:

$$\mathbf{RUFQAMTQSETOT}_{q} = \mathbf{RUFQAMT}_{q} + \mathbf{RRUFQAMT}_{q}$$

Where:

$$\text{RUFQAMT}_{q} = (\underset{m}{Max}(\text{MCPCRU}_{m}) * \text{RUFQ}_{q})$$

$$\text{RRUFQAMT}_{q} = \text{MCPCRU}_{rs} * \text{RRUFQ}_{q,\, rs}$$

The above variables are defined as follows:

Variable	Unit	Description
RUFQAMTQSETOT_{q}	$	*Reg-Up Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RRUFQAMT_{q}	$	*Reconfiguration Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RUFQAMT_{q}	$	*Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
MCPCRU_{m}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by market*—The MCPC for Reg-Up in the market *m*, for the hour.
MCPCRU_{rs}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by RSASM*—The MCPC for Reg-Up in the RSASM *rs*, for the hour.
RUFQ_{q}	MW	*Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.

$RRUFQ_{q,\,rs}$	MW	*Reconfiguration Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.

(b) The total charge of failure on Ancillary Service Supply Responsibility for Reg-Down by QSE, if applicable:

$$\mathbf{RDFQAMTQSETOT}_{q} = \mathbf{RDFQAMT}_{q} + \mathbf{RRDFQAMT}_{q}$$

Where:

$$RDFQAMT_{q} = (\underset{m}{Max}(MCPCRD_{m}) * RDFQ_{q})$$

$$RRDFQAMT_{q} = MCPCRD_{rs} * RRDFQ_{q,\,rs}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$RDFQAMTQSETOT_{q}$	$	*Reg-Down Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$RRDFQAMT_{q}$	$	*Reconfiguration Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$RDFQAMT_{q}$	$	*Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$MCPCRD_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by market*—The MCPC for Reg-Down in the market *m*, for the hour.
$MCPCRD_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by RSASM*—The MCPC for Reg-Down in the RSASM *rs*, for the hour.
$RDFQ_{q}$	MW	*Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$RRDFQ_{q,\,rs}$	MW	*Reconfiguration Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.

(c) The total charge of failure on Ancillary Service Supply Responsibility for RRS by QSE, if applicable:

$$\mathbf{RRFQAMTQSETOT}_{q} \quad = \quad \mathbf{RRFQAMT}_{q} + \mathbf{RRRFQAMT}_{q}$$

Where:

$$\text{RRFQAMT}_{q} \quad = \quad (\underset{m}{Max}(\text{MCPCRR}_{m}) * \text{RRFQ}_{q})$$

$$\text{RRRFQAMT}_{q} \quad = \quad \text{MCPCRR}_{rs} * \text{RRRFQ}_{q,\ rs}$$

The above variables are defined as follows:

Variable	Unit	Description
RRFQAMTQSETOT $_{q}$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQAMT $_{q}$	$	*Reconfiguration Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRFQAMT $_{q}$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
MCPCRR $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per market*—The MCPC for RRS in the market *m*, for the hour.
MCPCRR $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per RSASM*—The MCPC for RRS in the RSASM *rs*, for the hour.
RRFQ $_{q}$	MW	*Responsive Reserve Failure Quantity per QSE* - QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQ $_{q,\ rs}$	MW	*Reconfiguration Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.

(d) The total charge of failure on Ancillary Service Supply Responsibility for Non-Spin by QSE, if applicable:

$$\mathbf{NSFQAMTQSETOT}_{q} \quad = \quad \mathbf{NSFQAMT}_{q} + \mathbf{RNSFQAMT}_{q}$$

Where:

$$\text{NSFQAMT}_{q} \quad = \quad (\underset{m}{Max}(\text{MCPCNS}_{m}) * \text{NSFQ}_{q})$$

$$\text{RNSFQAMT}_{q} \quad = \quad \text{MCPCNS}_{rs} * \text{RNSFQ}_{q,\ rs}$$

The above variables are defined as follows:

Variable	Unit	Description
NSFQAMTQSETOT $_{q}$	$	*Non-Spin Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
RNSFQAMT $_{q}$	$	*Reconfiguration Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
NSFQAMT $_{q}$	$	*Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
MCPCNS $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by market*—The MCPC for Non-Spin in the market *m*, for the hour.
MCPCNS $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by RSASM*—The MCPC for Non-Spin in the RSASM *rs*, for the hour.
NSFQ $_{q}$	MW	*Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
RNSFQ $_{q,\ rs}$	MW	*Reconfiguration Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.

[NPRR863: Insert paragraph (e) below upon system implementation:]

(e) The total charge of failure on Ancillary Service Supply Responsibility for ECRS by QSE, if applicable:

$$\textbf{ECRFQAMTQSETOT}_{q} = \textbf{ECRFQAMT}_{q} + \textbf{RECRFQAMT}_{q}$$

Where:

$$\text{ECRFQAMT}_{q} = (\underset{m}{Max}(\text{MCPCECR}_{m}) * \text{ECRFQ}_{q})$$

$$\text{RECRFQAMT}_{q} = \text{MCPCECR}_{rs} * \text{RECRFQ}_{q,\ rs}$$

The above variables are defined as follows:

Variable	Unit	Description
ECRFQAMTQSETOT $_{q}$	$	*ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
RECRFQAMT $_{q}$	$	*Reconfiguration ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with

		reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
ECRFQAMT $_{q}$	$	*ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for ECRS, for the hour.
MCPCECR $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per market*—The MCPC for ECRS in the market *m*, for the hour.
MCPCECR $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per RSASM*—The MCPC for ECRS in the RSASM *rs*, for the hour.
ECRFQ $_{q}$	MW	*ERCOT Contingency Reserve Service Failure Quantity per QSE* - QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for ECRS, for the hour.
RECRFQ $_{q,\ rs}$	MW	*Reconfiguration ERCOT Contingency Reserve Service Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.

[NPRR1010: Delete Section 6.7.3 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.7.4 Adjustments to Cost Allocations for Ancillary Services Procurement

(1) Each QSE for which ERCOT purchases Ancillary Service capacity in the DAM, a SASM, or an RSASM, is charged for the QSE's share of the net costs incurred for each service. For each QSE, its share of the DAM costs has been calculated in Section 4.6.4, Settlement of Ancillary Services Procured in the DAM; its share of the net total costs incurred in the DAM, a SASM, or an RSASM less its DAM charge is calculated in this section.

(2) For Reg-Up, if applicable:

(a) The net total costs for Reg-Up for a given Operating Hour is calculated as follows:

$$\textbf{RUCOSTTOT} = \textbf{(-1) * (}\sum_{m}\textbf{(RTPCRUAMTTOT}_{m}\textbf{) + PCRUAMTTOT + RUFQAMTTOT + RUINFQAMTTOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for Reg-Up by market

$$\text{RTPCRUAMTTOT}_{m} = \sum_{q} \text{RTPCRUAMT}_{q,\, m}$$

Total payment of DAM-procured capacity for Reg-Up

$$\text{PCRUAMTTOT} = \sum_{q} \text{PCRUAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Up

$$\text{RUFQAMTTOT} = \sum_{q} \text{RUFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity for Reg-Up by QSE

$$\text{RTPCRUAMTQSETOT}_{q} = \sum_{m} \text{RTPCRUAMT}_{q,\, m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Reg-Up

$$\text{RUINFQAMTTOT} = \sum_{q} \text{RUINFQAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RUCOSTTOT	$	*Reg-Up Cost Total*—The net total costs for Reg-Up for the hour.
RTPCRUAMTTOT_{m}	$	*Procured Capacity for Reg-Up Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
$\text{RTPCRUAMT}_{q,\, m}$	$	*Procured Capacity for Reg-Up Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
RUFQAMTTOT	$	*Reg-Up Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
RUFQAMTQSETOT_{q}	$	*Reg-Up Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
$\text{RTPCRUAMTQSETOT}_{q}$	$	*Procured Capacity for Reg-Up Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Reg-Up, for the hour.
PCRUAMT_{q}	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q*, for the hour.
RUINFQAMTTOT	$	*Reg-Up Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
RUINFQAMT_{q}	$	*Reg-Up Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
PCRUAMTTOT	$	*Procured Capacity for Reg-Up Amount Total in DAM*—The total of the DAM Reg-Up payments for all QSEs, for the hour.
q	none	A QSE.

m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

[NPRR841: Replace paragraph (a) above with the following upon system implementation:]

(a) The net total costs for Reg-Up for a given Operating Hour is calculated as follows:

$$\mathbf{RUCOSTTOT} = \mathbf{(-1) * (\sum_{m} (RTPCRUAMTTOT_{\mathit{m}}) + PCRUAMTTOT + RUFQAMTTOT + RUINFQAMTTOT + RUMWINFATOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for Reg-Up by market

$$\text{RTPCRUAMTTOT}_{m} = \sum_{q} \text{RTPCRUAMT}_{q,\, m}$$

Total payment of DAM-procured capacity for Reg-Up

$$\text{PCRUAMTTOT} = \sum_{q} \text{PCRUAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Up

$$\text{RUFQAMTTOT} = \sum_{q} \text{RUFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity for Reg-Up by QSE

$$\text{RTPCRUAMTQSETOT}_{q} = \sum_{m} \text{RTPCRUAMT}_{q,\, m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Reg-Up

$$\text{RUINFQAMTTOT} = \sum_{q} \text{RUINFQAMT}_{q}$$

Total Real-Time DAM Make-Whole Payment for Reg-Up

$$\text{RUMWINFATOT} = \sum_{q} \text{RUMWINFA}_{q,\, h}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RUCOSTTOT	$	*Reg-Up Cost Total*—The net total costs for Reg-Up for the hour.
RTPCRUAMTTOT $_{m}$	$	*Procured Capacity for Reg-Up Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
RUMWINFATOT	$	*Reg-Up Make-Whole Infeasible Amount total*— The total Real-Time calculated payment to all QSEs, for their contribution of Reg-Up, to

		make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour.
$RUMWINFA_{q,\ h}$	$	*Reg-Up Make-Whole Infeasible Amount per QSE per hour*— The total Real-Time calculated payment to QSE *q,* for its contribution of Reg-Up, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour *h*.
$RTPCRUAMT_{q,\ m}$	$	*Procured Capacity for Reg-Up Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
RUFQAMTTOT	$	*Reg-Up Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
$RUFQAMTQSETOT_{q}$	$	*Reg-Up Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
$RTPCRUAMTQSETOT_{q}$	$	*Procured Capacity for Reg-Up Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Reg-Up, for the hour.
$PCRUAMT_{q}$	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q*, for the hour.
RUINFQAMTTOT	$	*Reg-Up Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
$RUINFQAMT_{q}$	$	*Reg-Up Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
PCRUAMTTOT	$	*Procured Capacity for Reg-Up Amount Total in DAM*—The total of the DAM Reg-Up payments for all QSEs, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(b) Each QSE’s share of the net total costs for Reg-Up for the Operating Hour is calculated as follows:

$$\mathbf{RUCOST}_{q} = \mathbf{RUPR * RUQ}_{q}$$

Where:

$$RUPR = RUCOSTTOT / RUQTOT$$

$$RUQTOT = \sum_{q} RUQ_{q}$$

$$RUQ_{q} = RUO_{q} - SARUQ_{q}$$

$$RUO_{q} = \sum_{q} (SARUQ_{q} + \sum_{m} (RTPCRU_{q,\ m}) + PCRU_{q} - RUFQ_{q} - RRUFQ_{q}) * HLRS_{q}$$

$$\text{SARUQ}_{q} = \text{DASARUQ}_{q} + \text{RTSARUQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RUCOST_{q}	$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up, for the hour.
RUPR	$/MW per hour	*Reg-Up Price*—The price for Reg-Up calculated based on the net total costs for Reg-Up, for the hour.
RUCOSTTOT	$	*Reg-Up Cost Total*—The net total costs for Reg-Up, for the hour. See item (2)(a) above.
RUQTOT	MW	*Reg-Up Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged Reg-Up quantity in the DAM and any and all SASMs, for the hour.
RUQ_{q}	MW	*Reg-Up Quantity per QSE*—The QSE *q*'s Ancillary Service Obligation minus its self-arranged Reg-Up quantity in the DAM and any and all SASMs, for the hour.
RUO_{q}	MW	*Reg-Up Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASARUQ_{q}	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARUQ_{q}	MW	*Self-Arranged Reg-Up Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
$\text{RTPCRU}_{q,\,m}$	MW	*Procured Capacity for Reg-Up per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Up, for the hour.
RUFQ_{q}	MW	*Reg-Up Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RRUFQ_{q}	MW	*Reconfiguration Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
HLRS_{q}	none	*The Hourly Load Ratio Share calculated for QSE q for the hour.* See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
PCRU_{q}	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
SARUQ_{q}	MW	*Total Self-Arranged Reg-Up Quantity per QSE for all markets*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Reg-Up for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTRUAMT}_{q} = \mathbf{RUCOST}_{q} - \mathbf{DARUAMT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTRUAMT $_q$	$	*Real-Time Reg-Up Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Reg-Up, for the hour.
RUCOST $_q$	$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up, for the hour.
DARUAMT $_q$	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Up, for the hour.
q	none	A QSE.

(3) For Reg-Down, if applicable:

(a) The net total costs for Reg-Down for a given Operating Hour is calculated as follows:

$$\mathbf{RDCOSTTOT = (-1) * (\sum_{m} (RTPCRDAMTTOT_{\mathit{m}}) + PCRDAMTTOT + RDFQAMTTOT + RDINFQAMTTOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for Reg-Down by market

$$\text{RTPCRDAMTTOT}_{m} = \sum_{q} \text{RTPCRDAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for Reg-Down

$$\text{PCRDAMTTOT} = \sum_{q} \text{PCRDAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Down

$$\text{RDFQAMTTOT} = \sum_{q} \text{RDFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity for Reg-Down by QSE

$$\text{RTPCRDAMTQSETOT}_{q} = \sum_{m} \text{RTPCRDAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Reg-Down

$$\text{RDINFQAMTTOT} = \sum_{q} \text{RDINFQAMT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RDCOSTTOT	$	*Reg-Down Cost Total*—The net total costs for Reg-Down, for the hour.
RTPCRDAMTTOT $_m$	$	*Procured Capacity for Reg-Down Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.

Variable	Unit	Description
$\text{RTPCRDAMT}_{q,\ m}$	$	*Procured Capacity for Reg-Down Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.
RDFQAMTTOT	$	*Reg-Down Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures on their Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
RDFQAMTQSETOT_{q}	$	*Reg-Down Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$\text{RTPCRDAMTQSETOT}_{q}$	$	*Procured Capacity for Reg-Down Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Reg-Down, for the hour.
PCRDAMT_{q}	$	*Procured Capacity for Reg-Down Amount per QSE for DAM*—The DAM Reg-Down payment for QSE *q*, for the hour.
PCRDAMTTOT	$	*Procured Capacity for Reg-Down Amount Total in DAM*—The total of the DAM Reg-Down payments for all QSEs for the hour.
RDINFQAMTTOT	$	*Reg-Down Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
RDINFQAMT_{q}	$	*Reg-Down Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of its Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

[NPRR841: Replace paragraph (a) above with the following upon system implementation:]

(a) The net total costs for Reg-Down for a given Operating Hour is calculated as follows:

$$\textbf{RDCOSTTOT} = \textbf{(-1) * (}\sum_{m}\textbf{(RTPCRDAMTTOT}_{m}\textbf{) + PCRDAMTTOT + RDFQAMTTOT + RDINFQAMTTOT + RDMWINFATOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for Reg-Down by market

$$\text{RTPCRDAMTTOT}_{m} = \sum_{q} \text{RTPCRDAMT}_{q,\ m}$$

Total payment of DAM-procured capacity for Reg-Down

$$\text{PCRDAMTTOT} = \sum_{q} \text{PCRDAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Down

$$\text{RDFQAMTTOT} = \sum_{q} \text{RDFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity for Reg-Down by QSE

$$\text{RTPCRDAMTQSETOT}_{q} = \sum_{m} \text{RTPCRDAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Reg-Down

$$\text{RDINFQAMTTOT} = \sum_{q} \text{RDINFQAMT}_{q}$$

Total Real-Time Day-Ahead Make-Whole Payment for Reg-Down

$$\text{RDMWINFATOT} = \sum_{q} \text{RDMWINFA}_{q,\,h}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RDCOSTTOT	$	*Reg-Down Cost Total*—The net total costs for Reg-Down, for the hour.
RTPCRDAMTTOT $_{m}$	$	*Procured Capacity for Reg-Down Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.
RTPCRDAMT $_{q,\ m}$	$	*Procured Capacity for Reg-Down Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.
RDFQAMTTOT	$	*Reg-Down Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures on their Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
RDMWINFATOT	$	*Reg-Down Make-Whole Infeasible Amount total*— The total Real-Time calculated payment to all QSEs, for their contribution of Reg-Down, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour.
RDMWINFA $_{q,\,h}$	$	*Reg-Down Make-Whole Infeasible Amount per QSE per hour*— The total Real-Time calculated payment to QSE *q,* for its contribution of Reg-Down, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour *h*.
RDFQAMTQSETOT $_{q}$	$	*Reg-Down Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RTPCRDAMTQSETOT $_{q}$	$	*Procured Capacity for Reg-Down Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Reg-Down, for the hour.
PCRDAMT $_{q}$	$	*Procured Capacity for Reg-Down Amount per QSE for DAM*—The DAM Reg-Down payment for QSE *q*, for the hour.
PCRDAMTTOT	$	*Procured Capacity for Reg-Down Amount Total in DAM*—The total of the DAM Reg-Down payments for all QSEs for the hour.
RDINFQAMTTOT	$	*Reg-Down Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Down, for the hour.

RDINFQAMT $_q$	$	*Reg-Down Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of its Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(b) Each QSE's share of the net total costs for Reg-Down for the Operating Hour is calculated as follows:

$$\mathbf{RDCOST}_{q} = \mathbf{RDPR * RDQ}_{q}$$

Where:

$$\text{RDPR} = \text{RDCOSTTOT / RDQTOT}$$

$$\text{RDQTOT} = \sum_{q} \text{RDQ}_{q}$$

$$\text{RDQ}_{q} = \text{RDO}_{q} - \text{SARDQ}_{q}$$

$$\text{RDO}_{q} = \sum_{q} (\text{SARDQ}_{q} + \sum_{m} (\text{RTPCRD}_{q,\,m}) + \text{PCRD}_{q} - \text{RDFQ}_{q} - \text{RRDFQ}_{q}) * \text{HLRS}_{q}$$

$$\text{SARDQ}_{q} = \text{DASARDQ}_{q} + \text{RTSARDQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RDCOST $_q$	$	*Reg-Down Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Down, for the hour.
RDPR	$/MW per hour	*Reg-Down Price*—The price for Reg-Down calculated based on the net total costs for Reg-Down, for the hour.
RDCOSTTOT	$	*Reg-Down Cost Total*—The net total costs for Reg-Down, for the hour. See item (3)(a) above.
RDQTOT	MW	*Reg-Down Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged Reg-Down quantity in the DAM and any and all SASMs for the hour.
RDQ $_q$	MW	*Reg-Down Quantity per QSE*—The QSE *q*'s Ancillary Service Obligation minus its self-arranged Reg-Down quantity in the DAM and any and all SASMs, for the hour.
RDO $_q$	MW	*Reg-Down Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASARDQ $_q$	MW	*Self-Arranged Reg-Down Quantity per QSE for DAM*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARDQ $_q$	MW	*Self-Arranged Reg-Down Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.

Variable	Unit	Description
$\text{RTPCRD}_{q,\,m}$	MW	*Procured Capacity for Reg-Down per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Down, for the hour.
RDFQ_{q}	MW	*Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RRDFQ_{q}	MW	*Reconfiguration Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
HLRS_{q}		*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
PCRD_{q}	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
SARDQ_{q}	MW	*Total Self-Arranged Reg-Down Quantity per QSE for all markets*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Reg-Down for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\textbf{RTRDAMT}_{q} \quad = \quad \textbf{RDCOST}_{q} - \textbf{DARDAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDAMT_{q}	\$	*Real-Time Reg-Down Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Reg-Down, for the hour.
RDCOST_{q}	\$	*Reg-Down Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Down, for the hour.
DARDAMT_{q}	\$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the hour.
q	none	A QSE.

(4) For RRS, if applicable:

(a) The net total costs for RRS for a given Operating Hour is calculated as follows:

$$\textbf{RRCOSTTOT} \quad = \quad (-1) * (\sum_{m} (\textbf{RTPCRRAMTTOT}_{m}) + \textbf{PCRRAMTTOT} + \textbf{RRFQAMTTOT} + \textbf{RRINFQAMTTOT})$$

Where:

Total payment of SASM- and RSASM-procured capacity for RRS by market

$$\text{RTPCRRAMTTOT}_{m} = \sum_{q} \text{RTPCRRAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for RRS

$$\text{PCRRAMTTOT} = \sum_{q} \text{PCRRAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for RRS

$$\text{RRFQAMTTOT} = \sum_{q} \text{RRFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity RRS Service by QSE

$$\text{RTPCRRAMTQSETOT}_{q} = \sum_{m} \text{RTPCRRAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for RRS

$$\text{RRINFQAMTTOT} = \sum_{q} \text{RRINFQAMT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for RRS, for the hour.
RTPCRRAMTTOT $_{m}$	$	*Procured Capacity for Responsive Reserve Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for RRS, for the hour.
RTPCRRAMT $_{q,\,m}$	$	*Procured Capacity for Responsive Reserve Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for RRS, for the hour.
RRFQAMTTOT	$	*Responsive Reserve Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for RRS, for the hour.
RRFQAMTQSETOT $_{q}$	$	*Responsive Reserve Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RTPCRRAMTQSETOT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for RRS, for the hour.
PCRRAMT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount per QSE for DAM*—The DAM RRS payment for QSE *q*, for the hour.
PCRRAMTTOT	$	*Procured Capacity for Responsive Reserve Amount Total in DAM*—The total of the DAM RRS payments for all QSEs, for the hour.
RRINFQAMTTOT	$	*Responsive Reserve Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for RRS, for the hour.
RRINFQAMT $_{q}$	$	*Responsive Reserve Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for RRS, for the hour.
q	none	A QSE.

Variable	Unit	Description
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

[NPRR841: Replace paragraph (a) above with the following upon system implementation:]

(a) The net total costs for RRS for a given Operating Hour is calculated as follows:

$$\mathbf{RRCOSTTOT} = \mathbf{(-1) * (\sum_{m} (RTPCRRAMTTOT_{m}) + PCRRAMTTOT + RRFQAMTTOT + RRINFQAMTTOT + RRMWINFATOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for RRS by market

$$\text{RTPCRRAMTTOT}_{m} = \sum_{q} \text{RTPCRRAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for RRS

$$\text{PCRRAMTTOT} = \sum_{q} \text{PCRRAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for RRS

$$\text{RRFQAMTTOT} = \sum_{q} \text{RRFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity for RRS by QSE

$$\text{RTPCRRAMTQSETOT}_{q} = \sum_{m} \text{RTPCRRAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for RRS

$$\text{RRINFQAMTTOT} = \sum_{q} \text{RRINFQAMT}_{q}$$

Total Real-Time Day-Ahead Make-Whole Payment for RRS

$$\text{RRMWINFATOT} = \sum_{q} \text{RRMWINFA}_{q,\,h}$$

The above variables are defined as follows:

Variable	Unit	Description
RRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for RRS, for the hour.
RTPCRRAMTTOT_{m}	$	*Procured Capacity for Responsive Reserve Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market m for RRS, for the hour.

RTPCRRAMT $_{q, m}$	$	*Procured Capacity for Responsive Reserve Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for RRS, for the hour.
RRFQAMTTOT	$	*Responsive Reserve Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for RRS, for the hour.
RRMWINFATOT	$	*Responsive Reserve Make-Whole Infeasible Amount total*— The total Real-Time calculated payment to all QSEs, for their contribution of RRS, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour.
RRMWINFA $_{q, h}$	$	*Responsive Reserve Make-Whole Infeasible Amount per QSE per hour*—The total Real-Time calculated payment to QSE *q,* for its contribution of RRS, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour *h*.
RRFQAMTQSETOT $_{q}$	$	*Responsive Reserve Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RTPCRRAMTQSETOT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for RRS, for the hour.
PCRRAMT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount per QSE in DAM*—The DAM RRS payment for QSE *q*, for the hour.
PCRRAMTTOT	$	*Procured Capacity for Responsive Reserve Amount Total in DAM*—The total of the DAM RRS payments for all QSEs, for the hour.
RRINFQAMTTOT	$	*Responsive Reserve Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for RRS, for the hour.
RRINFQAMT $_{q}$	$	*Responsive Reserve Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for RRS, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(b) Each QSE's share of the net total costs for RRS for the Operating Hour is calculated as follows:

$$\mathbf{RRCOST}_{q} = \mathbf{RRPR * RRQ}_{q}$$

Where:

$$\text{RRPR} = \text{RRCOSTTOT / RRQTOT}$$

$$\text{RRQTOT} = \sum_{q} \text{RRQ}_{q}$$

$$\text{RRQ}_{q} = \text{RRO}_{q} - \text{SARRQ}_{q}$$

$$\mathrm{RRO}_{q} = \sum_{q} (\mathrm{SARRQ}_{q} + \sum_{m} (\mathrm{RTPCRR}_{q,\,m}) + \mathrm{PCRR}_{q} - \mathrm{RRFQ}_{q} - \mathrm{RRRFQ}_{q}) * \mathrm{HLRS}_{q}$$

$$\mathrm{SARRQ}_{q} = \mathrm{DASARRQ}_{q} + \mathrm{RTSARRQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RRCOST_{q}	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for RRS, for the hour.
RRPR	$/MW per hour	*Responsive Reserve Price*—The price for RRS calculated based on the net total costs for RRS, for the hour.
RRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for RRS, for the hour. See item (4)(a) above.
RRQTOT	MW	*Responsive Reserve Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged RRS quantity in the DAM and any and all SASMs for the hour.
RRQ_{q}	MW	*Responsive Reserve Quantity per QSE*—The QSE *q*'s Ancillary Service Obligation minus its self-arranged RRS quantity in the DAM and any and all SASMs, for the hour.
RRO_{q}	MW	*Responsive Reserve Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
$\mathrm{DASARRQ}_{q}$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
$\mathrm{RTSARRQ}_{q}$	MW	*Self-Arranged Responsive Reserve Quantity per QSE for all SASMs*—The sum of all self-arranged RRS quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.
$\mathrm{RTPCRR}_{q,\,m}$	MW	*Procured Capacity for Responsive Reserve per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide RRS, for the hour.
RRFQ_{q}	MW	*Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQ_{q}	MW	*Reconfiguration Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
HLRS_{q}	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
PCRR_{q}	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total RRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
SARRQ_{q}	MW	*Total Self-Arranged Responsive Reserve Quantity per QSE for all markets*—The sum of all self-arranged RRS quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the RRS for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTRRAMT}_{q} = \mathbf{RRCOST}_{q} - \mathbf{DARRAMT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$RTRRAMT_{q}$	$	*Real-Time Responsive Reserve Amount per QSE*—The adjustment to QSE *q*'s share of the costs for RRS, for the hour.
$RRCOST_{q}$	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for RRS, for the hour.
$DARRAMT_{q}$	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for RRS, for the hour.
q	none	A QSE.

(5) For Non-Spin, if applicable:

(a) The net total costs for Non-Spin for a given Operating Hour is calculated as follows:

$$\mathbf{NSCOSTTOT} = \mathbf{(-1) * (\sum_{m} (RTPCNSAMTTOT_{m}) + PCNSAMTTOT + NSFQAMTTOT + NSINFQAMTTOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for Non-Spin by market

$$RTPCNSAMTTOT_{m} = \sum_{q} RTPCNSAMT_{q,\,m}$$

Total payment of DAM-procured capacity for Non-Spin

$$PCNSAMTTOT = \sum_{q} PCNSAMT_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Non-Spin

$$NSFQAMTTOT = \sum_{q} NSFQAMTQSETOT_{q}$$

Total payment of SASM- and RSASM-procured capacity for Non-Spin by QSE

$$RTPCNSAMTQSETOT_{q} = \sum_{m} RTPCNSAMT_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Non-Spin

$$NSINFQAMTTOT = \sum_{q} NSINFQAMT_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
NSCOSTTOT	$	*Non-Spin Cost Total*—The net total costs for Non-Spin, for the hour.
RTPCNSAMTTOT_{m}	$	*Procured Capacity for Non-Spin Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
$\text{RTPCNSAMT}_{q,\ m}$	$	*Procured Capacity for Non-Spin Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
NSFQAMTTOT	$	*Non-Spin Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
NSFQAMTQSETOT_{q}	$	*Non-Spin Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$\text{RTPCNSAMTQSETOT}_{q}$	$	*Procured Capacity for Non-Spin Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Non-Spin, for the hour.
PCNSAMT_{q}	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q*, for the hour.
PCNSAMTTOT	$	*Procured Capacity for Non-Spin Amount Total in DAM*—The total of the DAM Non-Spin payments for all QSEs, for the hour.
NSINFQAMTTOT	$	*Non-Spin Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
NSINFQAMT_{q}	$	*Non-Spin Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

[NPRR841: Replace paragraph (a) above with the following upon system implementation:]

(a) The net total costs for Non-Spin for a given Operating Hour is calculated as follows:

$$\textbf{NSCOSTTOT} = \textbf{(-1) * (}\sum_{m}\textbf{(RTPCNSAMTTOT}_{m}\textbf{) + PCNSAMTTOT + NSFQAMTTOT + NSINFQAMTTOT + NSMWINFATOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for Non-Spin by market

$$\text{RTPCNSAMTTOT}_{m} = \sum_{q} \text{RTPCNSAMT}_{q,\ m}$$

Total payment of DAM-procured capacity for Non-Spin

$$\text{PCNSAMTTOT} = \sum_{q} \text{PCNSAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Non-Spin

$$\text{NSFQAMTTOT} = \sum_{q} \text{NSFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity for Non-Spin by QSE

$$\text{RTPCNSAMTQSETOT}_{q} = \sum_{m} \text{RTPCNSAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Non-Spin

$$\text{NSINFQAMTTOT} = \sum_{q} \text{NSINFQAMT}_{q}$$

Total Real-Time Day-Ahead Make-Whole Payment for Non-Spin

$$\text{NSMWINFATOT} = \sum_{q} \text{NSMWINFA}_{q,\,h}$$

The above variables are defined as follows:

Variable	Unit	Description
NSCOSTTOT	$	*Non-Spin Cost Total*—The net total costs for Non-Spin, for the hour.
RTPCNSAMTTOT $_{m}$	$	*Procured Capacity for Non-Spin Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
RTPCNSAMT $_{q,\,m}$	$	*Procured Capacity for Non-Spin Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
NSFQAMTTOT	$	*Non-Spin Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
NSMWINFATOT	$	*Non Spin Make-Whole Infeasible Amount total*— The total Real-Time calculated payment to all QSEs, for their contribution of Non-Spin, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour.
NSMWINFA $_{q,\,h}$	$	*Non Spin Make-Whole Infeasible Amount per QSE per hour*— The total Real-Time calculated payment to QSE *q,* for its contribution of Non-Spin, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour *h*.
NSFQAMTQSETOT $_{q}$	$	*Non-Spin Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
RTPCNSAMTQSETOT $_{q}$	$	*Procured Capacity for Non-Spin Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Non-Spin, for the hour.
PCNSAMT $_{q}$	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q*, for the hour.
PCNSAMTTOT	$	*Procured Capacity for Non-Spin Amount Total in DAM*—The total of the DAM Non-Spin payments for all QSEs, for the hour.

NSINFQAMTTOT	$	*Non-Spin Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
NSINFQAMT $_q$	$	*Non-Spin Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(b) Each QSE's share of the net total costs for Non-Spin for the Operating Hour is calculated as follows:

$$\mathbf{NSCOST}_{q} = \mathbf{NSPR * NSQ}_{q}$$

Where:

$$\text{NSPR} = \text{NSCOSTTOT / NSQTOT}$$

$$\text{NSQTOT} = \sum_{q} \text{NSQ}_{q}$$

$$\text{NSQ}_{q} = \text{NSO}_{q} - \text{SANSQ}_{q}$$

$$\text{NSO}_{q} = \sum_{q} (\text{SANSQ}_{q} + \sum_{m} (\text{RTPCNS}_{q,\,m}) + \text{PCNS}_{q} - \text{NSFQ}_{q} - \text{RNSFQ}_{q}) * \text{HLRS}_{q}$$

$$\text{SANSQ}_{q} = \text{DASANSQ}_{q} + \text{RTSANSQ}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
NSCOST $_q$	$	*Non-Spin Cost per QSE*—QSE *q*'s share of the net total costs for Non-Spin, for the hour.
NSPR	$/MW per hour	*Non-Spin Price*—The price for Non-Spin calculated based on the net total costs for Non-Spin, for the hour.
NSCOSTTOT	$	*Non-Spin Cost Total*—The net total costs for Non-Spin for the hour. See item (5)(a) above.
NSQTOT	MW	*Non-Spin Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged Non-Spin quantity in the DAM and any and all SASMs, for the hour.
NSQ $_q$	MW	*Non-Spin Quantity per QSE*—The difference in QSE *q*'s Ancillary Service Obligation minus its self-arranged Non-Spin quantity in the DAM and any and all SASMs, for the hour.
NSO $_q$	MW	*Non-Spin Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASANSQ $_q$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE for DAM*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.

Variable	Unit	Description
RTSANSQ $_{q}$	MW	*Self-Arranged Non-Spin Quantity per QSE for all SASMs*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.
RTPCNS $_{q,\ m}$	MW	*Procured Capacity for Non-Spin per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Non-Spin, for the hour.
NSFQ $_{q}$	MW	*Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
RNSFQ $_{q}$	MW	*Reconfiguration Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
HLRS $_{q}$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
PCNS $_{q}$	MW	*Procured Capacity for Non-Spin Service per QSE in DAM*—The total Non-Spin capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
SANSQ $_{q}$	MW	*Total Self-Arranged Non-Spin Supplied Quantity per QSE for all markets*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Non-Spin for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTNSAMT}_{q} = \mathbf{NSCOST}_{q} - \mathbf{DANSAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTNSAMT $_{q}$	$	*Real-Time Non-Spin Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Non-Spin, for the hour.
NSCOST $_{q}$	$	*Non-Spin Cost per QSE*—QSE *q*'s share of the net total costs for Non-Spin, for the hour.
DANSAMT $_{q}$	$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin, for the hour.
q	none	A QSE.

[NPRR841 and NPRR863: Insert applicable portions of paragraph (6) below upon system implementation:]

(6) For ECRS, if applicable:

(a) The net total costs for ECRS for a given Operating Hour is calculated as follows:

$$\mathbf{ECRCOSTTOT} = (-1) * \left(\sum_{m} (\mathbf{RTPCECRAMTTOT}_{m}) + \mathbf{PCECRAMTTOT} + \mathbf{ECRFQAMTTOT} + \mathbf{ECRINFQAMTTOT} + \mathbf{ECRMWINFATOT}\right)$$

Where:

Total payment of SASM- and RSASM-procured capacity for ECRS by market

$$\text{RTPCECRAMTTOT}_{m} = \sum_{q} \text{RTPCECRAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for ECRS

$$\text{PCECRAMTTOT} = \sum_{q} \text{PCECRAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for ECRS

$$\text{ECRFQAMTTOT} = \sum_{q} \text{ECRFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity ECRS Service by QSE

$$\text{RTPCECRAMTQSETOT}_{q} = \sum_{m} \text{RTPCECRAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for ECRS

$$\text{ECRINFQAMTTOT} = \sum_{q} \text{ECRINFQAMT}_{q}$$

Total Real-Time Day-Ahead Make-Whole Payment for ECRS

$$\text{ECRMWINFATOT} = \sum_{q} \text{ECRMWINFA}_{q,\,h}$$

The above variables are defined as follows:

Variable	Unit	Description
ECRCOSTTOT	$	*ERCOT Contingency Reserve Service Cost Total*—The net total costs for ECRS, for the hour.
RTPCECRAMTTOT_{m}	$	*Procured Capacity for ERCOT Contingency Reserve Service Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for ECRS, for the hour.
$\text{RTPCECRAMT}_{q,\,m}$	$	*Procured Capacity for ERCOT Contingency Reserve Service Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for ECRS, for the hour.
ECRFQAMTTOT	$	*ERCOT Contingency Reserve Service Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for ECRS, for the hour.
ECRMWINFATOT	$	*ERCOT Contingency Reserve Service Make-Whole Infeasible Amount total*— The total Real-Time calculated payment to all QSEs, for their contribution of ECRS, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour.

ECRMWINFA $_{q,\,h}$	$	*ERCOT Contingency Reserve Service Make-Whole Infeasible Amount per QSE per hour*— The total Real-Time calculated payment to QSE *q,* for its contribution of ECRS, to make-whole the Startup and energy costs of all Resources committed in the DAM, for the hour *h*.
ECRFQAMTQSETOT $_{q}$	$	*ERCOT Contingency Reserve Service Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
RTPCECRAMTQSETOT $_{q}$	$	*Procured Capacity for ERCOT Contingency Reserve Service Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for ECRS, for the hour.
PCECRAMT $_{q}$	$	*Procured Capacity for ERCOT Contingency Reserve Service Amount per QSE for DAM*—The DAM ECRS payment for QSE *q*, for the hour.
PCECRAMTTOT	$	*Procured Capacity for ERCOT Contingency Reserve Service Amount Total in DAM*—The total of the DAM ECRS payments for all QSEs, for the hour.
ECRINFQAMTTOT	$	*ERCOT Contingency Reserve Service Infeasible Quantity Amount Total* —The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for ECRS, for the hour.
ECRINFQAMT $_{q}$	$	*ERCOT Contingency Reserve Service Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for ECRS, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(b) Each QSE's share of the net total costs for ECRS for the Operating Hour is calculated as follows:

$$\mathbf{ECRCOST}_{q} = \mathbf{ECRPR * ECRQ}_{q}$$

Where:

$$\text{ECRPR} = \text{ECRCOSTTOT / ECRQTOT}$$

$$\text{ECRQTOT} = \sum_{q} \text{ECRQ}_{q}$$

$$\text{ECRQ}_{q} = \text{ECRO}_{q} - \text{SAECRQ}_{q}$$

$$\text{ECRO}_{q} = \sum_{q} (\text{SAECRQ}_{q} + \sum_{m} (\text{RTPCECR}_{q,\,m}) + \text{PCECR}_{q} - \text{ECRFQ}_{q} - \text{RECRFQ}_{q}) * \text{HLRS}_{q}$$

$$\text{SAECRQ}_{q} = \text{DASAECRQ}_{q} + \text{RTSAECRQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
$ECRCOST_{q}$	$	*ERCOT Contingency Reserve Service Cost per QSE*—QSE *q*'s share of the net total costs for ECRS, for the hour.
ECRPR	$/MW per hour	*ERCOT Contingency Reserve Service Price*—The price for ECRS calculated based on the net total costs for ECRS, for the hour.
ECRCOSTTOT	$	*ERCOT Contingency Reserve Service Cost Total*—The net total costs for ECRS, for the hour. See item (6)(a) above.
ECRQTOT	MW	*ERCOT Contingency Reserve Service Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged ECRS quantity in the DAM and any and all SASMs for the hour.
$ECRQ_{q}$	MW	*ERCOT Contingency Reserve Service Quantity per QSE*—The QSE *q*'s Ancillary Service Obligation minus its self-arranged ECRS quantity in the DAM and any and all SASMs, for the hour.
$ECRO_{q}$	MW	*ERCOT Contingency Reserve Service Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
$DASAECRQ_{q}$	MW	*Day-Ahead Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE*—The self-arranged ECRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
$RTSAECRQ_{q}$	MW	*Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE for all SASMs*—The sum of all self-arranged ECRS quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.
$RTPCECR_{q, m}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide ECRS, for the hour.
$ECRFQ_{q}$	MW	*ERCOT Contingency Reserve Service Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$RECRFQ_{q}$	MW	*Reconfiguration ERCOT Contingency Reserve Service Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$HLRS_{q}$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour.* See Section 6.6.2.4.
$PCECR_{q}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per QSE in DAM*—The total ECRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
$SAECRQ_{q}$	MW	*Total Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE for all markets*—The sum of all self-arranged ECRS quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the ECRS for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTECRAMT}_{q} \quad = \quad \mathbf{ECRCOST}_{q} - \mathbf{DAECRAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTECRAMT $_q$	$	*Real-Time ERCOT Contingency Reserve Service Amount per QSE*—The adjustment to QSE *q*’s share of the costs for ECRS, for the hour.
ECRCOST $_q$	$	*ERCOT Contingency Reserve Service Cost per QSE*—QSE *q*’s share of the net total costs for ECRS, for the hour.
DAECRAMT $_q$	$	*Day-Ahead ERCOT Contingency Reserve Service Amount per QSE*—QSE *q*’s share of the DAM cost for ECRS, for the hour.
q	none	A QSE.

[NPRR1010: Replace Section 6.7.4 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.4 Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations

(1) Each QSE is charged or paid for net obligations for each Ancillary Service procured in the DAM. DAM costs are calculated for each QSE in accordance with Section 4.6.4, Settlement of Ancillary Services Procured in the DAM. DAM net total costs for Ancillary Service procured in the DAM are re-calculated for each QSE under this Section based on Real-Time Load Ratio Share (LRS). Payments and/or charges for Ancillary Service obligations are calculated by Operating Hour as follows:

(a) For Regulation Up Service (Reg-Up), if applicable:

$$\text{DARTPCRUAMT}_{q} = (\text{DARUNOBL}_{q} - \text{DASARUQ}_{q}) * \text{DARUPR} - \text{DARUAMT}_{q}$$

Where:

$$\text{DARUNOBL}_{q} = \text{DAPCRUQTOT} * \text{HLRS}_{q}$$

$$\text{DAPCRUQTOT} = \sum_{q} \left(\sum_{r} \text{PCRUR}_{r,\,q,\,DAM} + \text{DARUOAWD}_{q} + \text{DASARUQ}_{q}\right)$$

The above variables are defined as follows:

Variable	Unit	Description
DARTPCRUAMT $_q$	$	*Day-Ahead Updated Real-Time Procured Capacity for Reg-Up Amount by QSE* - The payment or charge to QSE *q* for Reg-Up, for the re-calculated Real-Time obligation, for the Operating Hour.
DARUPR	$/MW	*Day-Ahead Reg-Up Price*—The DAM Reg-Up price for the Operating Hour.
DARUNOBL $_q$	MW	*Day-Ahead Reg-Up New Obligation per QSE*—The updated Reg-Up Ancillary Service Obligation in Real-Time for QSE *q* for the Operating Hour.
DARUAMT $_q$	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*’s share of the DAM costs for Reg-Up for the Operating Hour.

$\text{PCRUR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for Reg-Up per Resource per QSE in DAM*—The Reg-Up capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DARUOAWD_q	MW	*Day-Ahead Reg-Up Award for the QSE* —The Reg-Up Only capacity awarded in the DAM to QSE *q* for the Operating Hour.
HLRS_q	none	*Hourly Load Ratio Share per QSE*—The Real-Time LRS as defined in Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour, for QSE *q*, for the Operating Hour.
DAPCRUQTOT	MW	*Day-Ahead Procured Capacity for Reg-Up Total*—The total Reg-Up capacity for all QSEs for all Reg-Up awarded and self-arranged in the DAM for the Operating Hour.
DASARUQ_q	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up capacity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
q	none	A QSE.
r	none	A Resource.

(b) For Regulation Down Service (Reg-Down), if applicable:

$$\text{DARTPCRDAMT}_q = (\text{DARDNOBL}_q - \text{DASARDQ}_q) * \text{DARDPR} - \text{DARDAMT}_q$$

Where:

$$\text{DARDNOBL}_q = \text{DAPCRDQTOT} * \text{HLRS}_q$$

$$\text{DAPCRDQTOT} = \sum_q \left(\sum_r \text{PCRDR}_{r,\,q,\,DAM} + \text{DARDOAWD}_q + \text{DASARDQ}_q \right)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
DARTPCRDAMT_q	$	*Day-Ahead Updated Real-Time Procured Capacity for Reg-Down Amount by QSE* - The payment or charge to QSE *q* for Reg-Down, for the re-calculated Real-Time obligation, for the Operating Hour.
DARDPR	$/MW	*Day-Ahead Reg-Down Price*—The DAM Reg-Down price for the Operating Hour.
DARDNOBL_q	MW	*Day-Ahead Reg-Down New Obligation per QSE*—The updated Reg-Down Ancillary Service Obligation in Real-Time, for QSE *q*, for the Operating Hour.
DARDAMT_q	$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the Operating Hour.
$\text{PCRDR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for Reg-Down per Resource per QSE in DAM*—The Reg-Down capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DARDOAWD_q	MW	*Day-Ahead Reg-Down Only Award for the QSE* —The Reg-Down Only capacity awarded in the DAM to QSE *q* for the Operating Hour.

HLRS_{q}	none	*Hourly Load Ratio Share per QSE*—The Real-Time as defined in Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour for QSE *q*, for the Operating Hour.
DAPCRDQTOT	MW	*Day-Ahead Procured Capacity for Reg-Down Total*—The total Reg-Down capacity for all QSEs for all Reg-Down awarded and self-arranged, in the DAM for the Operating Hour.
DASARDQ_{q}	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The self-arranged Reg-Down capacity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
q	none	A QSE.
r	none	A Resource.

(c) For Responsive Reserve (RRS), if applicable:

$$\text{DARTPCRRAMT}_{q} = (\text{DARRNOBL}_{q} - \text{DASARRQ}_{q}) * \text{DARRPR} - \text{DARRAMT}_{q}$$

Where:

$$\text{DARRNOBL}_{q} = \text{DAPCRRQTOT} * \text{HLRS}_{q}$$

$$\text{DAPCRRQTOT} = \sum_{q} (\text{PCRRR}_{r,\,q,\,DAM} + \text{DARROAWD}_{q} + \text{DASARRQ}_{q})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
DARTPCRRAMT_{q}	$	*Day-Ahead Updated Real-Time Procured Capacity for Responsive Reserve Amount by QSE* - The payment or charge to QSE *q* for RRS, for the re-calculated Real-Time obligation, for the Operating Hour.
DARRPR	$/MW	*Day-Ahead Responsive Reserve Price*—The DAM RRS price for the Operating Hour.
DARRNOBL_{q}	MW	*Day-Ahead Responsive Reserve New Obligation per QSE*—The updated RRS Ancillary Service Obligation in Real-Time for QSE *q* for the Operating Hour.
DARRAMT_{q}	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for RRS for the Operating Hour.
$\text{PCRRR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for Responsive Reserve per Resource per QSE in DAM*—The RRS capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DARROAWD_{q}	MW	*Day-Ahead Responsive Reserve Only Award for the QSE* —The RRS Only capacity awarded in the DAM to QSE *q* for the Operating Hour.
HLRS_{q}	none	Hourly Load Ratio Share per QSE—The Real-Time LRS as defined in Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour for QSE *q* for the Operating Hour.
DAPCRRQTOT	MW	*Day-Ahead Procured Capacity for Responsive Reserve Total* —The total RRS capacity for all QSEs for all RRS awarded and self-arranged in the DAM for the Operating Hour.

DASARRQ_{q}	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS capacity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
q	none	A QSE.
r	none	A Resource.

(d) For Non-Spinning Reserve (Non-Spin), if applicable:

$$\text{DARTPCNSAMT}_{q} = (\text{DANSNOBL}_{q} - \text{DASANSQ}_{q}) * \text{DANSPR} - \text{DANSAMT}_{q}$$

Where:

$$\text{DANSNOBL}_{q} = \text{DAPCNSQTOT} * \text{HLRS}_{q}$$

$$\text{DAPCNSQTOT} = \sum_{q} (\sum_{r} \text{PCNSR}_{r,\, q,\, DAM} + \text{DANSOAWD}_{q} + \text{DASANSQ}_{q})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
DARTPCNSAMT_{q}	$	*Day-Ahead Updated Real-Time Procured Capacity for Non-Spin Amount by QSE* - The payment or charge to QSE *q* for Non-Spin for the re-calculated Real-Time obligation for the Operating Hour.
DANSPR	$/MW	*Day-Ahead Non-Spin Price*—The DAM Non-Spin price for the Operating Hour.
DANSNOBL_{q}	MW	*Day-Ahead Non-Spin New Obligation per QSE*—The updated Non-Spin Ancillary Service Obligation in Real-Time for QSE *q* for the Operating Hour.
$\text{PCNSR}_{r,\, q,\, DAM}$	MW	*Procured Capacity for Non-Spin per Resource per QSE in DAM*—The Non-Spin capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DANSOAWD_{q}	MW	*Day-Ahead Non-Spin Only Award for the QSE* — The Non-Spin Only capacity awarded in the DAM to QSE *q* for the Operating Hour.
DANSAMT_{q}	$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin for the Operating Hour.
HLRS_{q}	none	*Hourly Load Ratio Share per QSE*—The Real-Time LRS as defined in Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour for QSE *q* for the Operating Hour.
DAPCNSQTOT	MW	*Day-Ahead Procured Capacity for Non-Spin Total* —The total Non-Spin capacity for all QSEs for all Non-Spin awarded and self-arranged in the DAM for the Operating Hour.
DASANSQ_{q}	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE*—The self-arranged Non-Spin capacity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
q	none	A QSE.
r	none	A Resource.

(e) For ERCOT Contingency Reserve Service (ECRS), if applicable:

$$\text{DARTPCECRAMT}_{q} = (\text{DAECRNOBL}_{q} - \text{DASAECRQ}_{q}) * \text{DAECRPR} - \text{DAECRAMT}_{q}$$

Where:

$$\text{DAECRNOBL}_{q} = \text{DAPCECRQTOT} * \text{HLRS}_{q}$$

$$\text{DAPCECRQTOT} = \sum_{q} \left(\sum_{r} \text{PCECRR}_{r,\, q,\, DAM} + \text{DAECROAWD}_{q} + \text{DASAECRQ}_{q} \right)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
DARTPCECRAMT_{q}	\$	*Day-Ahead Updated Real-Time Procured Capacity for ERCOT Contingency Reserve Service Amount by QSE* - The payment or charge to QSE *q* for ECRS for the re-calculated Real-Time obligation for the Operating Hour.
DAECRPR	\$/MW	*Day-Ahead ERCOT Contingency Reserve Price*—The DAM ECRS price for the Operating Hour.
DAECRNOBL_{q}	MW	*Day-Ahead ERCOT Contingency Reserve Service New Obligation per QSE*—The updated ECRS Ancillary Service Obligation in Real-Time for QSE *q* for the Operating Hour.
$\text{PCECRR}_{r,\, q,\, DAM}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per Resource per QSE in DAM*—The ECRS capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DAECROAWD_{q}	MW	*Day-Ahead ERCOT Contingency Reserve Service Only Award for the QSE* — The ECRS Only capacity awarded in the DAM to QSE *q* for the Operating Hour.
DAECRAMT_{q}	\$	*Day-Ahead ERCOT Contingency Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for ECRS for the Operating Hour.
HLRS_{q}	none	*Hourly Load Ratio Share per QSE*—The Real-Time LRS as defined in Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour for QSE *q* for the Operating Hour.
DAPCECRQTOT	MW	*Day-Ahead Procured Capacity for ERCOT Contingency Reserve Total*—The total ECRS capacity for all QSEs for all ECRS awarded and self-arranged in the DAM for the Operating Hour.
DASAECRQ_{q}	MW	*Day-Ahead Self-Arranged ERCOT Contingency Reserve Quantity per QSE*—The self-arranged ECRS capacity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
q	none	A QSE.
r	none	A Resource.

6.7.5 *Real-Time Ancillary Service Imbalance Payment or Charge*

(1) Based on the Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and a Real-Time Off-Line Reserve Price Adders, ERCOT shall calculate Ancillary Service imbalance Settlement, which will make Resources indifferent to the utilization of their capacity for energy or Ancillary Service reserves, as set forth in this Section.

(2) The payment or charge to each QSE for Ancillary Service imbalance is calculated based on the price calculation set forth in paragraph (12) of Section 6.5.7.3, Security Constrained Economic Dispatch, and applied to the following amounts for each QSE:

(a) The amount of Real-Time Metered Generation from all Generation Resources, represented by the QSE for the 15-minute Settlement Interval;

[NPRR987: Replace paragraph (a) above with the following upon system implementation:]

(a) The amount of Real-Time Metered Generation from all Generation Resources and Energy Storage Resources (ESRs), represented by the QSE for the 15-minute Settlement Interval;

(b) The amount of On-Line capacity based on the telemetered High Sustained Limit (HSL) for all On-Line Generation Resources, the telemetered consumption from Load Resources with a validated Ancillary Service Schedule for RRS controlled by high-set under-frequency relay or Non-Spin, and the capacity from Controllable Load Resources available to SCED;

[NPRR863 and NPRR987: Replace applicable portions of paragraph (b) above with the following upon system implementation:]

(b) The amount of On-Line capacity based on the telemetered High Sustained Limit (HSL) for all On-Line Generation Resources and ESRs, the telemetered consumption from Load Resources with a validated Ancillary Service Schedule for ECRS or RRS controlled by high-set under-frequency relay or Non-Spin, and the capacity from Controllable Load Resources available to SCED, including capacity from modeled Controllable Load Resources associated with ESRs;

(c) The amount of Ancillary Service Resource Responsibility for Reg-Up, RRS and Non-Spin for all Generation and Load Resources represented by the QSE for the 15-minute Settlement Interval.

[NPRR863 and NPRR987: Replace applicable portions of paragraph (c) above with the following upon system implementation:]

(c) The amount of Ancillary Service Resource Responsibility for Reg-Up, ECRS, RRS and Non-Spin for all Generation Resources, ESRs, and Load Resources represented by the QSE for the 15-minute Settlement Interval.

(3) Resources meeting one or more of the following conditions will be excluded from the amounts calculated pursuant to paragraphs (2)(a) and (b) above:

(a) Nuclear Resources;

(b) Resources with a telemetered ONTEST, STARTUP (except Resources with Non-Spin Ancillary Service Resource Responsibility greater than zero), or SHUTDOWN Resource Status excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

[NPRR1085: Replace paragraph (b) above with the following upon system implementation:]

(b) Resources with a telemetered ONTEST, ONHOLD, STARTUP (except Resources with Non-Spin Ancillary Service Resource Responsibility greater than zero), or SHUTDOWN Resource Status excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

(c) Resources with a telemetered net real power (in MW) less than 95% of their telemetered Low Sustained Limit (LSL) excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility.

[NPRR987: Replace paragraph (c) above with the following upon system implementation:]

(c) Resources with a telemetered net real power (in MW) less than 95% of their telemetered Low Sustained Limit (LSL) excluding the following:

(i) Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

(ii) ESRs.

(4) Reliability Must-Run (RMR) Units and Reliability Unit Commitment (RUC) Resources On-Line during the hour due to an ERCOT instruction, except for any RUC Resource committed by a RUC Dispatch Instruction where that Resource's QSE subsequently opted out of RUC Settlement pursuant to paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process, those RUC Resources that had a Three-Part Supply Offer cleared in the DAM for the hour, 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 Energy Emergency Alert (EEA) condition, and any Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration to a different configuration with additional capacity, as described in paragraph (3) of Section 5.5.2, will be excluded from the amounts calculated for the 15-minute Settlement Interval pursuant to paragraphs (2)(a), (b), and (c) above.

[NPRR885 and NPRR1092: Replace applicable portions of paragraph (4) above with the following upon system implementation:]

(4) Reliability Must-Run (RMR) Units, and Must-Run Alternatives (MRAs), and Reliability Unit Commitment (RUC) Resources On-Line during the hour due to an ERCOT instruction will be excluded from the amounts calculated for the 15-minute Settlement Interval pursuant to paragraphs (2)(a), (b), and (c) above except for:

(a) Those RUC Resources that had a Three-Part Supply Offer cleared in the DAM for the hour;

(b) 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 Energy Emergency Alert (EEA) condition;

(c) Any Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration to a different configuration with additional capacity, as described in paragraph (3) of Section 5.5.2, Reliability Unit Commitment (RUC) Process; or

(d) Any RUC Resource committed by a RUC Dispatch Instruction where that Resource's QSE subsequently opted out of RUC Settlement pursuant to paragraph (14) of Section 5.5.2.

(5) The Real-Time Off-Line Reserve Capacity for the QSE (RTOFFCAP) shall be administratively set to zero when the SCED snapshot of the Physical Responsive Capability (PRC) is less than or equal to the PRC MW at which EEA Level 1 is initiated.

(6) Resources that have a Under Generation Volume (UGEN) greater than zero, and are not-exempt from a Base Point Deviation Charge, as set forth in Section 6.6.5, Base Point Deviation Charge, or are not already excluded in paragraphs (3) or (4) above, for the 15-

minute Settlement Interval will have the UGEN amounts removed from the amounts calculated pursuant to paragraphs (2)(a) and (b) above.

[NPRR987: Replace paragraph (6) above with the following upon system implementation:]

(6) Resources that have an Under Generation Volume (UGEN) or an Under Performance Volume (UPESR) greater than zero, and are not exempt from a Base Point Deviation Charge, as set forth in Section 6.6.5, Base Point Deviation Charge, or are not already excluded in paragraphs (3) or (4) above, for the 15-minute Settlement Interval will have the UGEN or UPESR amounts removed from the amounts calculated pursuant to paragraphs (2)(a) and (b) above.

(7) The payment or charge to each QSE for the Ancillary Service imbalance for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTASIAMT}_{q} = (-1) * [(\mathbf{RTASOLIMB}_{q} * \mathbf{RTRSVPOR}) + (\mathbf{RTASOFFIMB}_{q} * \mathbf{RTRSVPOFF})]$$

$$\mathbf{RTRDASIAMT}_{q} = (-1) * (\mathbf{RTASOLIMB}_{q} * \mathbf{RTRDP})$$

Where:

$$\text{RTASOLIMB}_{q} = \text{RTOLCAP}_{q} - [((\text{SYS\_GEN\_DISCFACTOR} * \text{RTASRESP}_{q}) * ¼) - \text{RTASOFF}_{q} - \text{RTRUCNBBRESP}_{q} - \text{RTCLRNSRESP}_{q} - \text{RTNCLRNSRESP}_{q} - \text{RTRMRRESP}_{q}]$$

[NPRR1131: Replace the formula "RTASOLIMB $_{q}$" above with the following upon system implementation:]

$$\text{RTASOLIMB}_{q} = \text{RTOLCAP}_{q} - [((\text{SYS\_GEN\_DISCFACTOR} * \text{RTASRESP}_{q}) * ¼) - \text{RTASOFF}_{q} - \text{RTRUCNBBRESP}_{q} - \text{RTNCLRNSRESP}_{q} - \text{RTRMRRESP}_{q}]$$

Where:

$$\text{RTASOFF}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \sum_{p} \text{RTASOFFR}_{q,r,p}$$

$$\text{RTRUCNBBRESP}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \text{RTRUCASA}_{q,r} * ¼$$

$$\text{RTCLRNSRESP}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \sum_{p} \text{RTCLRNSRESPR}_{q,r,p}$$

[NPRR1131: Delete the formula "RTCLRNSRESP $_{q}$" above upon system implementation.]

$$\text{RTNCLRNSRESP}_{q} = \quad \text{SYS\_GEN\_DISCFACTOR} * \sum_{r}\sum_{p} \text{RTNCLRNSRESPR}_{q,\,r,\,p}$$

$$\text{RTRMRRESP}_{q} = \quad \text{SYS\_GEN\_DISCFACTOR} * \sum_{q}\sum_{r}\sum_{p} (\text{HRRADJ}_{q,\,r,\,p} + \text{HRUADJ}_{q,\,r,\,p} + \text{HNSADJ}_{q,\,r,\,p}) * \tfrac{1}{4}$$

[NPRR863: Replace the formula "RTRMRRESP $_{q}$" above with the following upon system implementation:]

$$\text{RTRMRRESP}_{q} = \quad \text{SYS\_GEN\_DISCFACTOR} * \sum_{q}\sum_{r}\sum_{p} (\text{HRRADJ}_{q,\,r,\,p} + \text{HECRADJ}_{q,\,r,\,p} + \text{HRUADJ}_{q,\,r,\,p} + \text{HNSADJ}_{q,\,r,\,p}) * \tfrac{1}{4}$$

$$\text{RTOLCAP}_{q} = \quad (\text{RTOLHSL}_{q} - \text{RTMGQ}_{q} - \text{SYS\_GEN\_DISCFACTOR} * (\sum_{r}\sum_{p} \text{UGENA}_{q,\,r,\,p})) + \text{RTCLRCAP}_{q} + \text{RTNCLRCAP}_{q}$$

[NPRR987: Replace the formula "RTOLCAP $_{q}$" above with the following upon system implementation:]

$$\text{RTOLCAP}_{q} = \quad (\text{RTOLHSL}_{q} - \text{RTMGQ}_{q} - \text{SYS\_GEN\_DISCFACTOR} * (\sum_{r}\sum_{p} (\text{UGENA}_{q,\,r,\,p} + \text{UPESRA}_{q,\,r,\,p}))) + \text{RTCLRCAP}_{q} + \text{RTNCLRCAP}_{q} + \text{RTESRCAP}_{q}$$

Where:

$$\text{RTNCLRCAP}_{q} = \quad \text{Min}(\text{Max}(\text{RTNCLRNPC}_{q} - \text{RTNCLRLPC}_{q}, 0.0), \text{RTNCLRRRS}_{q} * 1.5)$$

[NPRR863: Replace the formula "RTNCLRCAP $_{q}$" above with the following upon system implementation:]

$$\text{RTNCLRCAP}_{q} = \quad \text{Min}(\text{Max}(\text{RTNCLRNPC}_{q} - \text{RTNCLRLPC}_{q}, 0.0), (\text{RTNCLRECRS}_{q} + \text{RTNCLRRRS}_{q}) * 1.5)$$

$$\text{RTNCLRRRS}_{q} = \quad \text{SYS\_GEN\_DISCFACTOR} * \sum_{r}\sum_{p} \text{RTNCLRRRSR}_{q,\,r,\,p}$$

[NPRR863: Insert the formula “RTNCLRECRS $_q$” below upon system implementation:]

$$\text{RTNCLRECRS}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTNCLRECRSR}_{q, r, p}$$

$$\text{RTNCLRNPC}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTNCLRNPCR}_{q, r, p}$$

$$\text{RTNCLRLPC}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTNCLRLPCR}_{q, r, p}$$

$$\text{RTOLHSL}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTOLHSLRA}_{q, r, p}$$

$$\text{RTMGQ}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTMGA}_{q, r, p}$$

If $\text{RTMGA}_{q, r, p} > \text{RTOLHSLRA}_{q, r, p}$

Then $\text{RTMGA}_{q, r, p} = \text{RTOLHSLRA}_{q, r, p}$

[NPRR987: Insert the language below upon system implementation:]

Where for a Controllable Load Resource other than a modeled Controllable Load Resource associated with an Energy Storage Resource (ESR):

$$\text{RTCLRCAP}_q = \text{RTCLRNPC}_q - \text{RTCLRLPC}_q - \text{RTCLRNS}_q + \text{RTCLRREG}_q$$

[NPRR1131: Replace the formula “RTCLRCAP $_q$” above with the following upon system implementation:]

$$\text{RTCLRCAP}_q = \text{RTCLRNPC}_q - \text{RTCLRLPC}_q + \text{RTCLRREG}_q$$

$$\text{RTCLRNPC}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTCLRNPCR}_{\mathbf{q, r, p}}$$

$$\text{RTCLRLPC}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTCLRLPCR}_{\mathbf{q, r, p}}$$

$$\text{RTCLRNS}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTCLRNSR}_{\mathbf{q, r, p}}$$

[NPRR1131: Delete the formula "RTCLRNS $_q$" above upon system implementation.]

$$\text{RTCLRREG}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTCLRREGR}_{q,\,r,\,p}$$

Where:

$$\text{RTRSVPOR} = \sum_y (\text{RNWF}_y * \text{RTORPA}_y)$$

$$\text{RTASOFFIMB}_q = \text{RTOFFCAP}_q - (\text{RTASOFF}_q + \text{RTCLRNSRESP}_q + \text{RTNCLRNSRESP}_q)$$

[NPRR1131: Replace the formula "RTASOFFIMB $_q$" above with the following upon system implementation:]

$$\text{RTASOFFIMB}_q = \text{RTOFFCAP}_q - (\text{RTASOFF}_q + \text{RTNCLRNSRESP}_q)$$

$$\text{RTOFFCAP}_q = (\text{SYS\_GEN\_DISCFACTOR} * \text{RTCST30HSL}_q) + (\text{SYS\_GEN\_DISCFACTOR} * \text{RTOFFNSHSL}_q) + \text{RTCLRNS}_q + \text{RTNCLRNSCAP}_q$$

[NPRR1131: Replace the formula "RTOFFCAP $_q$" above with the following upon system implementation:]

$$\text{RTOFFCAP}_q = (\text{SYS\_GEN\_DISCFACTOR} * \text{RTCST30HSL}_q) + (\text{SYS\_GEN\_DISCFACTOR} * \text{RTOFFNSHSL}_q) + \text{RTNCLRNSCAP}_q$$

$$\text{RTNCLRNSCAP}_q = \text{Min}(\text{Max}(\text{RTNCLRNPC}_q - \text{RTNCLRLPC}_q, 0.0), \text{RTNCLRNS}_q * 1.5)$$

$$\text{RTNCLRNS}_q = \text{SYS\_GEN\_DISCFACTOR} * \sum_r \sum_p \text{RTNCLRNSR}_{q,\,r,\,p}$$

$$\text{RTRSVPOFF} = \sum_y (\text{RNWF}_y * \text{RTOFFPA}_y)$$

$$\text{RTRDP} = \sum_y (\text{RNWF}_y * \text{RTORDPA}_y)$$

$$\text{RNWF}_y = \text{TLMP}_y \,/ \sum_y \text{TLMP}_y$$

[NPRR987: Insert the language below upon system implementation:]

Where for an ESR:

$$\text{RTESRCAP}_{q} = \sum_{g} (\text{RTESRCAPR}_{q,\,g,\,p})$$

Where:

$$\text{RTESRCAPR}_{q,\,g,\,p} = \text{Min}[(\text{RTOLHSLRA}_{q,\,r,\,p} - \text{RTMGA}_{q,\,r,\,p} + \text{RTCLRNPCR}_{q,\,r,\,p}), (\text{RTCLRNPCR}_{q,\,r,\,p} + \text{SOCT}_{q,\,r} - \text{SOCOM}_{q,\,r})]$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTASIAMT_{q}	$	*Real-Time Ancillary Service Imbalance Amount*—The total payment or charge to QSE q for the Real-Time Ancillary Service imbalance associated with Operating Reserve Demand Curve (ORDC) for each 15-minute Settlement Interval.
RTRDASIAMT_{q}	$	*Real-Time Reliability Deployment Ancillary Service Imbalance Amount*—The total payment or charge to QSE q for the Real-Time Ancillary Service imbalance associated with Reliability Deployments for each 15-minute Settlement Interval.
RTASOLIMB_{q}	MWh	*Real-Time Ancillary Service On-Line Reserve Imbalance for the QSE* —The Real-Time Ancillary Service On-Line reserve imbalance for the QSE q, for each 15-minute Settlement Interval.
RTORPA_{y}	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time Price Adder for On-Line Reserves for the SCED interval y.
RTOFFPA_{y}	$/MWh	*Real-Time Off-Line Reserve Price Adder per interval*—The Real-Time Price Adder for Off-Line Reserves for the SCED interval y.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the SCED interval y.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval y.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval y within the 15-minute Settlement Interval.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRSVPOFF	$/MWh	*Real-Time Reserve Price for Off-Line Reserves*—The Real-Time Reserve Price for Off-Line Reserves for the 15-minute Settlement Interval.

Variable	Unit	Description
$RTOLCAP_{q}$	MWh	*Real-Time On-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of On-Line Resources available for the QSE *q*, for the 15-minute Settlement Interval.
$RTOLHSLRA_{q, r, p}$	MWh	*Real-Time Adjusted On-Line High Sustained Limit for the Resource*—The Real-Time telemetered HSL for the Resource *r* represented by QSE *q* at Resource Node *p* that is available to SCED, integrated over the 15-minute Settlement Interval, and adjusted pursuant to paragraphs (3) and (4) above.
$RTOLHSL_{q}$	MWh	*Real-Time On-Line High Sustained Limit for the QSE*—The Real-Time telemetered HSL for all Generation Resources available to SCED, pursuant to paragraphs (3) and (4) above, integrated over the 15-minute Settlement Interval for the QSE *q*, discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time On-Line High Sustained Limit for the QSE*—The integrated Real-Time telemetered HSL for all Generation Resources, not including modeled Generation Resources associated with ESRs, available to SCED, pursuant to paragraphs (3) and (4) above, integrated over the 15-minute Settlement Interval for the QSE *q*, discounted by the system-wide discount factor.
$RTASRESP_{q}$	MW	*Real-Time Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, RRS and Non-Spin pursuant to Section 4.4.7.4, Ancillary Service Supply Responsibility, for all Generation and Load Resources for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, ECRS, RRS and Non-Spin pursuant to Section 4.4.7.4, Ancillary Service Supply Responsibility, for all Generation and Load Resources for the QSE *q*, for the 15-minute Settlement Interval.

Variable	**Unit**	**Description**
$RTCLRCAP_{q}$	MWh	*Real-Time Capacity from Controllable Load Resources for the QSE*—The Real-Time capacity and Reg-Up minus Non-Spin available from all Controllable Load Resources available to SCED for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Capacity from Controllable Load Resources for the QSE*—The Real-Time capacity and Reg-Up minus Non-Spin available from all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs available to SCED for the QSE *q*, integrated over the 15-minute Settlement Interval.
$RTNCLRCAP_{q}$	MWh	*Real-Time Capacity from Non-Controllable Load Resources carrying Responsive Reserve for the QSE*—The Real-Time capacity for all Load Resources other than Controllable Load Resources that have a validated Real-Time RRS Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Capacity from Non-Controllable Load Resources carrying ERCOT Contingency Reserve or Responsive Reserve for the QSE*—The Real-Time capacity for all Load Resources other than Controllable Load Resources that have a validated Real-Time ECRS or RRS Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval.
$RTNCLRRRS_{q}$	MWh	*Real-Time Non-Controllable Load Resources Responsive Reserve for the QSE*—The validated Real-Time telemetered RRS Ancillary Service Supply Responsibility for all Load Resources other than Controllable Load Resources for QSE *q* discounted by the system-wide discount factor, integrated over the 15-minute Settlement Interval.
$RTNCLRRRSR_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Responsive Reserve*—The validated Real-Time telemetered RRS Ancillary Service Resource Responsibility for the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
[NPRR863: Insert the variables “RTNCLRECRS $_{q}$” and “RTNCLRECRSR $_{q, r, p}$” below upon system implementation:]		
RTNCLRECRS $_{q}$	MWh	*Real-Time Non-Controllable Load Resources ERCOT Contingency Reserve for the QSE*—The validated Real-Time telemetered ECRS Ancillary Service Supply Responsibility for all Load Resources other than Controllable Load Resources for QSE *q* discounted by the system-wide discount factor, integrated over the 15-minute Settlement Interval.
RTNCLRECRSR $_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource ERCOT Contingency Reserve* —The validated Real-Time telemetered ECRS Ancillary Service Resource Responsibility for the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.
RTNCLRNPCR $_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Net Power Consumption*—The Real-Time net real power consumption from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Net Power Consumption*—The Real-Time net real power consumption from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval.
RTNCLRLPCR $_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Low Power Consumption*—The Real-Time Low Power Consumption (LPC) from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Low Power Consumption*—The Real-Time Low Power Consumption (LPC) from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval

Variable	Unit	Description
RTNCLRNPC $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Net Power Consumption for the QSE*—The Real-Time net real power consumption from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Net Power Consumption for the QSE*—The Real-Time net real power consumption from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTNCLRLPC $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Low Power Consumption for the QSE*—The Real-Time LPC from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Low Power Consumption for the QSE*—The Real-Time LPC from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTNCLRNSCAP $_{q}$	MWh	*Real-Time Capacity from Non-Controllable Load Resources carrying Non-Spin for the QSE*—The Real-Time capacity for all Load Resources that are not Controllable Load Resources and that have a validated Real-Time Non-Spin Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval.
RTNCLRNSR $_{q, r, p}$	MWh	*Real-Time Non-Spin Schedule for the Non-Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Load Resource *r* that is not a Controllable Load Resources represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.
RTNCLRNS $_{q}$	MWh	*Real-Time Non-Spin Schedule for Non-Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Load Resources that are not Controllable Load Resources for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.

Variable	Unit	Description
RTNCLRNSRESP $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Load Resources that are not Controllable Load Resources discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.
RTNCLRNSRESPR $_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Load Resource *r* that is not a Controllable Load Resource represented by QSE *q* at Resource Node *p* integrated over the 15-minute Settlement Interval.
RTCLRNPCR $_{q, r, p}$	MWh	*Real-Time Net Power Consumption from the Controllable Load Resource*—The Real-Time net real power consumption from the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Net Power Consumption from the Controllable Load Resource*—The Real-Time net real power consumption from the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval.
RTCLRNPC $_{q}$	MWh	*Real-Time Net Power Consumption from Controllable Load Resources for the QSE*—The Real-Time net real power consumption from all Controllable Load Resources available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Net Power Consumption from Controllable Load Resources for the QSE*—The Real-Time net real power consumption from all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor.

Variable	Unit	Description
RTCLRLPCR $_{q, r, p}$	MWh	*Real-Time Low Power Consumption for the Controllable Load Resource*—The Real-Time LPC from the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Low Power Consumption for the Controllable Load Resource*—The Real-Time LPC from the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval.
RTCLRLPC $_{q}$	MWh	*Real-Time Low Power Consumption from Controllable Load Resources for the QSE*—The Real-Time LPC from Controllable Load Resources available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Low Power Consumption from Controllable Load Resources for the QSE*—The Real-Time LPC from Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor.
RTCLRREG $_{q}$	MWh	*Real-Time Controllable Load Resources Regulation-Up Schedule for the QSE*—The Real-Time Reg-Up Ancillary Service Schedule from all Controllable Load Resources not available to SCED with Primary Frequency Response for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTCLRREGR $_{q, r, p}$	MWh	*Real-Time Controllable Load Resource Regulation-Up Schedule for the Resource*—The validated Real-Time Reg-Up Ancillary Service Schedule for the Controllable Load Resource not available to SCED *r* represented by QSE *q* at Resource Node *p* with Primary Frequency Response, integrated over the 15-minute Settlement Interval.
RTMGA $_{q, r, p}$	MWh	*Real-Time Adjusted Metered Generation per QSE per Settlement Point per Resource*—The adjusted metered generation, pursuant to paragraphs (3) and (4) above, of Generation Resource *r* represented by QSE *q* at Resource Node *p* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Description
RTMGQ_{q}	MWh	*Real-Time Metered Generation per QSE*—The metered generation, discounted by the system-wide discount factor, of all generation Resources represented by QSE *q* in Real-Time for the 15-minute Settlement Interval, pursuant to paragraphs (3) and (4) above. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Metered Generation per QSE*—The metered generation, discounted by the system-wide discount factor, of all Generation Resources, not including modeled Generation Resources associated with ESRs, represented by QSE *q* in Real-Time for the 15-minute Settlement Interval, pursuant to paragraphs (3) and (4) above.

[NPRR987: Insert the variables "RTESRCAPR $_{q, g, p}$", "RTESRCAP $_{q}$", "SOCT $_{q, r}$", and "SOCOM $_{q, r}$" below upon system implementation:]

$\text{RTESRCAPR}_{q, g, p}$	MWh	*Real-Time Capacity from an Energy Storage Resource* – Capacity provided by an ESR *g*, represented by QSE *q* at Resource Node *p,* which considers energy limitations of the ESR and potentially higher contribution when charging for the15-minute Settlement Interval.
RTESRCAP_{q}	MWh	*Real-Time Capacity from Energy Storage Resources per QSE* – Capacity provided by all ESRs, represented by QSE *q*, for the 15-minute Settlement Interval.
$\text{SOCT}_{q, r}$	MWh	*State of Charge Telemetered by an Energy Storage Resource* – The average telemetered state of charge of Resource *r*, represented by QSE *q*, over the 15-minute Settlement Interval.
$\text{SOCOM}_{q, r}$	MWh	*State of Charge Operating Minimum for an Energy Storage Resource* –The average telemetered state of charge operating minimum of Resource *r*, represented by QSE *q*, over the 15-minute Settlement Interval.

RTASOFFIMB_{q}	MWh	*Real-Time Ancillary Service Off-Line Reserve Imbalance for the QSE*—The Real-Time Ancillary Service Off-Line reserve imbalance for the QSE *q*, for each 15-minute Settlement Interval.
RTOFFCAP_{q}	MWh	*Real-Time Off-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of Off-Line Resources available for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Off-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of Off-Line Resources, not including modeled Generation Resources associated with ESRs, available for the QSE *q*, for the 15-minute Settlement Interval.

Variable	Unit	Description
RTCST30HSL $_{q}$	MWh	*Real-Time Generation Resources with Cold Start Available in 30 Minutes*—The Real-Time telemetered HSLs of Generation Resources, excluding Intermittent Renewable Resources (IRRs), that have telemetered an OFF Resource Status and can be started from a cold temperature state in 30 minutes for the QSE *q*, time-weighted over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Generation Resources with Cold Start Available in 30 Minutes*—The Real-Time telemetered HSLs of Generation Resources, excluding Intermittent Renewable Resources (IRRs) and modeled Generation Resources associated with ESRs, that have telemetered an OFF Resource Status and can be started from a cold temperature state in 30 minutes for the QSE *q*, time-weighted over the 15-minute Settlement Interval.
RTOFFNSHSL $_{q}$	MWh	*Real-Time Generation Resources with Off-Line Non-Spin Schedule*—The Real-Time telemetered HSLs of Generation Resources that have telemetered an OFFNS Resource Status for the QSE *q*, time-weighted over the 15-minute Settlement Interval. ***[NPRR1069 and NPRR1135: Replace applicable portions of the description above with the following upon system implementation of NPRR987 for NPRR1069; or upon system implementation for NPRR1135:]*** *Real-Time Generation Resources with Off-Line Non-Spin Schedule*—The Real-Time telemetered HSLs of Off-Line Generation Resources, not including modeled Generation Resources associated with ESRs, that have telemetered an OFFNS Resource Status for the QSE *q*, time-weighted over the 15-minute Settlement Interval.
RTASOFFR $_{q, r, p}$	MWh	*Real-Time Ancillary Service Schedule for the Off-Line Generation Resource*—The validated Real-Time telemetered Ancillary Service Schedule for the Off-Line Generation Resource *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
RTASOFF $_{q}$	MWh	*Real-Time Ancillary Service Schedule for Off-Line Generation Resources for the QSE*—The Real-Time telemetered Ancillary Service Schedule for all Off-Line Generation Resources discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Ancillary Service Schedule for Off-Line Generation Resources for the QSE*—The Real-Time telemetered Ancillary Service Schedule for all Off-Line Generation Resources, not including modeled Generation Resources associated with ESRs, discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.
HRRADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Responsive Reserve at Adjustment Period*—The RRS Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last Current Operating Plan (COP) and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
[NPRR863: Insert the variable “HECRADJ $_{q, r, p}$” below upon system implementation:]		
HECRADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for ERCOT Contingency Reserve Service at Adjustment Period*—The ECRS Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last Current Operating Plan (COP) and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
HRUADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Reg-Up at Adjustment Period*—The Regulation Up Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last COP and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
HNSADJ $_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Non-Spin at Adjustment Period*—The Non-Spin Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last COP and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.

Variable	Unit	Description
RTRUCNBBRESP $_{q}$	MWh	*Real-Time RUC Ancillary Service Supply Responsibility for the QSE in Non-Buy-Back hours*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, RRS and Non-Spin pursuant to the Ancillary Service awards, for the 15-minute Settlement Interval that falls within a RUC-Committed Hour, discounted by the system-wide discount factor for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Supply Responsibility for the QSE in Non-Buy-Back hours*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, ECRS, RRS, and Non-Spin pursuant to the Ancillary Service awards, for the 15-minute Settlement Interval that falls within a RUC-Committed Hour, discounted by the system-wide discount factor for the QSE *q*.
RTRUCASA $_{q,\ r}$	MW	*Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, RRS, and Non-Spin for the hour that includes the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, ECRS, RRS, and Non-Spin for the hour that includes the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*.
RTCLRNSRESP $_{q}$	MWh	*Real-Time Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Controllable Load Resources available to SCED discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
[NPRR1131: Delete the variable "RTCLRNSRESP $_q$" above upon system implementation.]		
RTCLRNSRESPR $_{q, r, p}$	MWh	*Real-Time Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Controllable Load Resource *r* or modeled Controllable Load Resource associated with an ESR represented by QSE *q* at Resource Node *p* available to SCED, integrated over the 15-minute Settlement Interval.
[NPRR1131: Delete the variable "RTCLRNSRESPR $_{q, r, p}$" above upon system implementation.]		
RTRMRRESP $_q$	MWh	*Real-Time Ancillary Service Supply Responsibility for RMR Units represented by the QSE*—The Real-Time Ancillary Service Supply Responsibility as set forth in the end of the Adjustment Period COP for Reg-Up, RRS, and Non-Spin for all RMR Units discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Ancillary Service Supply Responsibility for RMR Units represented by the QSE*—The Real-Time Ancillary Service Supply Responsibility as set forth in the end of the Adjustment Period COP for Reg-Up, ECRS, RRS, and Non-Spin for all RMR Units discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.

Variable	Unit	Description
$\text{RTCLRNSR}_{q, r, p}$	MWh	*Real-Time Non-Spin Schedule for the Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Spin Schedule for the Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.
[NPRR1131: Delete the variable "$\text{RTCLRNSR}_{q, r, p}$" above upon system implementation.]		
RTCLRNS_{q}	MWh	*Real-Time Non-Spin Schedule for Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Controllable Load Resources for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Spin Schedule for Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
[NPRR1131: Delete the variable "RTCLRNS_{q}" above upon system implementation.]		
SYS_GEN_DISCFACTOR	none	*System-Wide Discount Factor* – The system-wide discount factor used to discount inputs used in the calculation of Real-Time Ancillary Services Imbalance payment or charge is calculated as the average of the currently approved Reserve Discount Factors (RDFs) applied to the temperatures from the current Season from the year prior.
$\text{UGEN}_{q, r, p}$	MWh	*Under Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval.
$\text{UGENA}_{q, r, p}$	MWh	*Adjusted Under Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval adjusted pursuant to paragraph (6) above.

Variable	Unit	Description
[NPRR987: Insert the variables "UPESR $_{q, r, p}$" and "UPESRA $_{q, r, p}$" below upon system implementation:]		
UPESR $_{q, r, p}$	MWh	*Under-Performance Volumes per QSE per Settlement Point per Resource*—The amount the ESR under-performed divided evenly among the modeled Generation and Controllable Load Resources *r* in the ESR, represented by QSE *q* at Resource Node *p,* for the 15-minute Settlement Interval.
UPESRA $_{q, r, p}$	MWh	*Adjusted Under-Performance Volumes per QSE per Settlement Point per Resource* — The amount the ESR under-performed divided evenly among the modeled Generation and Controllable Load Resources *r* in the ESR, represented by QSE *q* at Resource Node *p,* for the 15-minute Settlement Interval adjusted pursuant to paragraph (6) above.
r	none	A Generation or Load Resource.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
[NPRR987: Insert the variable "g" below upon system implementation:]		
g	none	An ESR.

(8) The payment to each QSE for the Ancillary Service reserves associated with RUC Resources that have received a RUC Dispatch to provide Ancillary Services in which the 15-minute Settlement Interval is part of a RUC Buy-Back Hour based on the RUC opt out provision set forth in paragraph (14) of Section 5.5.2 for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTRUCRSVAMT}_{q} = (-1) * (\mathbf{RTRUCRESP}_{q} * \mathbf{RTRSVPOR})$$

$$\mathbf{RTRDRUCRSVAMT}_{q} = (-1) * (\mathbf{RTRUCRESP}_{q} * \mathbf{RTRDP})$$

Where:

$$\text{RTRUCRESP}_{q} = \sum_{r} \text{RTRUCASA}_{q,r} * 1/4$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUCRSVAMT $_{q}$	$	*Real-Time RUC Ancillary Service Reserve Amount*—The total payment |to QSE *q* for the Real-Time RUC Ancillary Service Reserve payment associated with ORDC for each 15-minute Settlement Interval.

Variable	Unit	Description
RTRDRUCRSVAMT $_q$	$	*Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount*—The total payment |to QSE *q* for the Real-Time RUC Ancillary Service Reserve payment associated with reliability deployments for each 15-minute Settlement Interval.
RTRUCRESP $_q$	MWh	*Real-Time RUC Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility pursuant to the Ancillary Service awards for Reg-Up, RRS, and Non-Spin for all RUC Resources that have opted out per paragraph (14) of Section 5.5.2 for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility pursuant to the Ancillary Service awards for Reg-Up, ECRS, RRS, and Non-Spin for all RUC Resources that have opted out per paragraph (14) of Section 5.5.2 for the QSE *q*, for the 15-minute Settlement Interval.
RTRUCASA $_{q,\ r}$	MW	*Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, RRS, and Non-Spin for the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, ECRS, RRS, and Non-Spin for the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
q	none	A QSE.
r	none	A Generation Resource.

[NPRR1010: Replace Section 6.7.5 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5 Real-Time Ancillary Service Charges and Payments

[NPRR1010: Insert Section 6.7.5.1 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.1 Real-Time Ancillary Service Imbalance Payment or Charge

(1) The payments or charges to each QSE for Real-Time Ancillary Services are as follows:

(a) Ancillary Service Imbalance payment or charges based on Real-Time Ancillary Service prices with an imbalance quantity determined by:

(i) The Real-Time Ancillary Service awarded; minus

(ii) The amount of Day-Ahead Market (DAM) Ancillary Service awards cleared in the DAM; minus

(iii) The amount of DAM Self Arranged Ancillary Services; plus

(iv) The amount of Ancillary Service Trades where the QSE is the buyer; minus

(v) The amount of Ancillary Service Trades where the QSE is the seller.

(b) Charges for Ancillary Service Only Offers purchased in the DAM.

(c) Charges for any Ancillary Service trade overage per paragraph (7) of Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.

[NPRR1010: Insert Section 6.7.5.2 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.2 Regulation Up Service Payments and Charges

(1) Reg-Up Imbalance Payment or Charge:

$$\mathbf{RTRUIMBAMT}_{q} = (-1) * [\sum_{r} [\mathbf{RTRUREV}_{q,r} - (1/4) * (\mathbf{PCRUR}_{r,q,DAM} * \mathbf{RTMCPCRU})] - (1/4) * (\mathbf{DASARUQ}_{q} * \mathbf{RTMCPCRU}) + (1/4) * (\mathbf{RUTP}_{q} - \mathbf{RUTS}_{q}) * \mathbf{RTMCPCRU}]$$

Where:

$$\mathbf{RTRUREV}_{q,r} = (1/4) * \mathbf{RTRUAWD}_{q,r} * \mathbf{RTMCPCRUR}_{q,r}$$

$$\mathbf{RTMCPCRUR}_{q,r} = \sum_{y} (\mathbf{RURWF}_{q,r,p,y} * (\mathbf{RTMCPCRUS}_{y} + \mathbf{RTRDPARUS}_{y}))$$

$$\mathbf{RTRUAWD}_{q,r} = \sum_{y} (\mathbf{RNWF}_{y} * \mathbf{RTRUAWDS}_{q,r,p,y})$$

Where:

$$\text{RURWF}_{q,r,p,y} = [\max(0.001, \text{RTRUAWDS}_{q,r,p,y}) * \text{TLMP}_{y}] / [\sum_{y} \max(0.001, \text{RTRUAWDS}_{q,r,p,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUIMBAMT $_{q}$	$	*Real-Time Reg-Up Imbalance Amount for the QSE*— The total payment or charge to QSE *q* for the Real-Time Reg-Up imbalance for each 15-minute Settlement Interval.
RTRUREV $_{q, r}$	$	*Real-Time Reg-Up Revenue*— The Real-Time Reg-Up revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDPARUS $_{y}$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Up per SCED interval* - The Real-Time price adder for Reg-Up that captures the impact of reliability deployments on Reg-Up prices for the SCED interval y.
RTRUAWD $_{q, r}$	MW	*Real-Time Reg-Up Award per Resource per QSE*— The Reg-Up amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRUAWDS $_{q, r, p, y}$	MW	*Real-Time Reg-Up Award per Resource per QSE per SCED interval* - The Reg-Up amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRUR $_{q, r}$	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up per Resource per QSE*— The Real-Time MCPC for Reg-Up for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
RTMCPCRUS $_{y}$	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up per SCED interval* - The Real-Time MCPC for Reg-Up for the SCED interval *y.*
PCRUR $_{r, q, DAM}$	MW	*Procured Capacity for Reg-Up per Resource per QSE in DAM*— The Reg-Up capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
DASARUQ $_q$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
RUTP $_q$	MW	*Trade Purchases for Reg-Up for the QSE*— The final approved trade purchases for QSE *q* for Reg-Up for the Operating Hour.
RUTS $_q$	MW	*Trade Sales for Reg-Up for the QSE*— The final approved trade sales for QSE *q* for Reg-Up for the Operating Hour.
TLMP $_y$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
RNWF $_y$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval *y* within the Settlement Interval.
RURWF $_{q, r, p, y}$	none	*Reg-Up Resource Node Weighting Factor per interval* - The Reg-Up Resource weight, based on Reg-Up awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
p	none	A Resource Node Settlement Point.

(2) Reg-Up Only Charge:

$$\mathbf{RTRUOAMT}_{q} = \quad \mathbf{(1/4) * DARUOAWD}_{q} \mathbf{* RTMCPCRU}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUOAMT $_q$	$	*Real-Time Reg-Up Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Up Only awards for each 15-minute Settlement Interval.
DARUOAWD $_q$	MW	*Day-Ahead Reg-Up Only Award for the QSE*— The Reg-Up only capacity awarded in the DAM to the QSE *q* for the Operating Hour.
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
q	none	A QSE.

(3) Reg-Up Trade Overage Charges:

$$\mathbf{RTRUTOAMT}_{q} = \quad \mathbf{(1/4) * RTRUTO}_{q} \mathbf{* RTMCPCRU}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUTOAMT $_q$	\$	*Real-Time Reg-Up Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Up trade overages for each 15-minute Settlement Interval.
RTRUTO $_q$	MW	*Real-Time Reg-Up Trade Overage for the QSE* — The quantity of submitted Reg-Up trades in excess of DAM self-arrangement quantities for the QSE *q* for the Operating Hour.
RTMCPCRU	\$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.3 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.3 Regulation Down Service Payments and Charges

(1) Reg-Down Imbalance Payment or Charge:

$$\mathbf{RTRDIMBAMT}_{q} = (-1) * [\sum_{r} [\mathbf{RTRDREV}_{q,r} - (1/4) * (\mathbf{PCRDR}_{r,q,DAM} * \mathbf{RTMCPCRD})] - (1/4) * (\mathbf{DASARDQ}_{q} * \mathbf{RTMCPCRD}) + (1/4) * (\mathbf{RDTP}_{q} - \mathbf{RDTS}_{q}) * \mathbf{RTMCPCRD}]$$

Where:

$$\mathbf{RTRDREV}_{q,r} = (1/4) * \mathbf{RTRDAWD}_{q,r} * \mathbf{RTMCPCRDR}_{q,r}$$

$$\mathbf{RTMCPCRDR}_{q,r} = \sum_{y} (\mathbf{RDRWF}_{q,r,p,y} * (\mathbf{RTMCPCRDS}_{y} + \mathbf{RTRDPARDS}_{y}))$$

$$\mathbf{RTRDAWD}_{q,r} = \sum_{y} (\mathbf{RNWF}_{y} * \mathbf{RTRDAWDS}_{q,r,p,y})$$

Where:

$$\text{RDRWF}_{q,r,p,y} = [\max(0.001, \text{RTRDAWDS}_{q,r,p,y}) * \text{TLMP}_{y}] / [\sum_{y} \max(0.001, \text{RTRDAWDS}_{q,r,p,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTRDIMBAMT_{q}$	$	*Real-Time Reg-Down Imbalance Amount for the QSE*— The total payment or charge to QSE *q* for the Real-Time Reg-Down imbalance for each 15-minute Settlement Interval.
$RTRDAWD_{q, r}$	MW	*Real-Time Reg-Down Award per Resource per QSE* - The Reg-Down amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTRDREV_{q, r}$	$	*Real-Time Reg-Down Revenue*— The Real-Time Reg-Down revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTRDAWDS_{q, r, p, y}$	MW	*Real-Time Reg-Down Award per Resource per QSE per SCED interval* - The Reg-Down Amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RTMCPCRDR_{q, r}$	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down per Resource per QSE*— The Real-Time MCPC for Reg-Down for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTMCPCRDS_{y}$	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down per SCED interval* - The Real-Time MCPC for Reg-Down for the SCED interval *y*.
$PCRDR_{r, q, DAM}$	MW	*Procured Capacity for Reg-Down per Resource per QSE in DAM*—The Reg-Down capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
$RTRDPARDS_{y}$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Down per SCED interval* - The Real-Time price adder for Reg-Down that captures the impact of reliability deployments on Reg-Down prices for the SCED interval *y*.
$DASARDQ_{q}$	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE* —The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
$RDTP_{q}$	MW	*Trade Purchases for Reg-Down for the QSE*— The trade purchases for QSE *q* for Reg-Down for the Operating Hour.
$RDTS_{q}$	MW	*Trade Sales for Reg-Down for the QSE*— The trade sales for QSE *q* for Reg-Down for the Operating Hour.
$TLMP_{y}$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval y within the Settlement Interval.

RDRWF $_{q, r, p, y}$	none	*Regulation Down Resource Node Weighting Factor per interval* - The Reg-Down Resource weight, based on Reg-Down awards, used in the Real-Time MCPC calculation for the portion of the SCED interval y within the Settlement Interval. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
p	none	A Resource Node Settlement Point.

(2) Reg-Down Only Charge:

$$\mathbf{RTRDOAMT}_{q} = \quad \mathbf{(1/4) * DARDOAWD}_{q} \mathbf{* RTMCPCRD}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDOAMT $_{q}$	$	*Real-Time Reg-Down Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Down only awards for each 15-minute Settlement Interval.
DARDOAWD $_{q}$	MW	*Day-Ahead Reg-Down Only Award for the QSE*— The Reg-Down only capacity awarded in the DAM to the QSE *q* for the Operating Hour.
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
q	none	A QSE.

(3) Reg-Down Trade Overage Charge:

$$\mathbf{RTRDTOAMT}_{q} = \quad \mathbf{(1/4) * RTRDTO}_{q} \mathbf{* RTMCPCRD}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDTOAMT $_{q}$	$	*Real-Time Reg-Down Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Down trade overages for each 15-minute Settlement Interval.
RTRDTO $_{q}$	MW	*Real-Time Reg-Down Trade Overage for the QSE* — The quantity of submitted Reg-Down trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.4 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.4 Responsive Reserve Payments and Charges

(1) RRS Imbalance Payment or Charge:

$$\mathbf{RTRRIMBAMT}_{q} = (-1) * [\sum_{r} [\mathbf{RTRRREV}_{q,r} - (1/4) * (\mathbf{PCRRR}_{r,q,DAM} * \mathbf{RTMCPCRR})] - (1/4) * (\mathbf{DASARRQ}_{q} * \mathbf{RTMCPCRR}) + (1/4) * (\mathbf{RRTP}_{q} - \mathbf{RRTS}_{q}) * \mathbf{RTMCPCRR}]$$

Where:

$$\mathbf{RTRRREV}_{q,r} = (1/4) * \mathbf{RTRRAWD}_{q,r} * \mathbf{RTMCPCRRR}_{q,r}$$

$$\mathbf{RTMCPCRRR}_{q,r} = \sum_{y} (\mathbf{RRRWF}_{q,r,p,y} * (\mathbf{RTMCPCRRS}_{y} + \mathbf{RTRDPARRS}_{y}))$$

$$\mathbf{RTRRAWD}_{q,r} = \sum_{y} (\mathbf{RNWF}_{y} * \mathbf{RTRRAWDS}_{q,r,p,y})$$

Where:

$$\text{RRRWF}_{q,r,p,y} = [\max(0.001, \text{RTRRAWDS}_{q,r,p,y}) * \text{TLMP}_{y}] / [\sum_{y} \max(0.001, \text{RTRRAWDS}_{q,r,p,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTRRIMBAMT_{q}	$	*Real-Time Responsive Reserve Imbalance Amount for the QSE*— The total payment or charge to QSE *q* for the Real-Time RRS imbalance for each 15-minute Settlement Interval.
$\text{RTRRAWD}_{q,r}$	MW	*Real-Time Responsive Reserve Award per Resource per QSE*— The RRS amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTRRREV}_{q,r}$	$	*Real-Time Responsive Reserve Revenue*— The Real-Time RRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

$RTRDPARRS_{y}$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Responsive Reserve per SCED interval* – The Real-Time price adder for RRS that captures the impact of reliability deployments on RRS prices for the SCED interval y.
$RTRRAWDS_{q, r, p, y}$	MW	*Real-Time Responsive Reserve Award per Resource per QSE per SCED interval* - The RRS amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RTMCPCRRR_{q, r}$	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve per Resource per QSE*— The Real-Time MCPC for RRS for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTMCPCRRS_{y}$	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve per SCED interval* - The Real-Time MCPC for RRS for the SCED interval *y*.
$PCRRR_{r, q, DAM}$	MW	*Procured Capacity for Responsive Reserve per Resource per QSE in DAM*—The RRS capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRR	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
$DASARRQ_{q}$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
$RRTP_{q}$	MW	*Trade Purchases for Responsive Reserve for the QSE*— The trade purchases for QSE *q* for RRS for the Operating Hour.
$RRTS_{q}$	MW	*Trade Sales for Responsive Reserve for the QSE* — The trade sales for QSE *q* for RRS for the Operating Hour.
$TLMP_{y}$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval y within the Settlement Interval.
$RRRWF_{q, r, p, y}$	none	*Responsive Reserve Resource Node Weighting Factor per interval* - The RRS Resource weight, based on RRS awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
p	none	A Resource Node Settlement Point.

(2) RRS Only Charge:

$$\mathbf{RTRROAMT}_{q} = (1/4) * \mathbf{DARROAWD}_{q} * \mathbf{RTMCPCRR}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTRROAMT_{q}$	\$	*Real-Time Responsive Reserve Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for RRS only awards for each 15-minute Settlement Interval.
$DARROAWD_{q}$	MW	*Day-Ahead Responsive Reserve Only Award for the QSE*— The RRS only capacity awarded in the DAM to the QSE *q* for the Operating Hour.
RTMCPCRR	\$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
q	none	A QSE.

(3) RRS Trade Overage Charge:

$$\mathbf{RTRRTOAMT}_{q} = (1/4) * \mathbf{RTRRTO}_{q} * \mathbf{RTMCPCRR}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTRRTOAMT_{q}$	\$	*Real-Time Responsive Reserve Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for RRS trade overages for each 15-minute Settlement Interval.
$RTRRTO_{q}$	MW	*Real-Time Responsive Reserve Trade Overage for the QSE* — The quantity of submitted RRS trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.
RTMCPCRR	\$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.5 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.5 Non-Spinning Reserve Service Payments and Charges

(1) Non-Spin Imbalance Payment or Charge:

$$\mathbf{RTNSIMBAMT}_{q} = (-1) * [\sum_{r} [\mathbf{RTNSREV}_{q,r} - (1/4) * (\mathbf{PCNSR}_{r,q,DAM} * \mathbf{RTMCPCNS})] - (1/4) * (\mathbf{DASANSQ}_{q} * \mathbf{RTMCPCNS}) + (1/4) * (\mathbf{NSTP}_{q} - \mathbf{NSTS}_{q}) * \mathbf{RTMCPCNS}]$$

Where:

$$\mathbf{RTNSREV}_{q,r} = (1/4) * \mathbf{RTNSAWD}_{q,r} * \mathbf{RTMCPCNSR}_{q,r}$$

$$\mathbf{RTMCPCNSR}_{q,r} = \sum_{y} (\mathbf{NSRWF}_{q,r,p,y} * (\mathbf{RTMCPCNSS}_{y} + \mathbf{RTRDPANSS}_{y}))$$

$$\mathbf{RTNSAWD}_{q,r} = \sum_{y} (\mathbf{RNWF}_{y} * \mathbf{RTNSAWDS}_{q,r,p,y})$$

Where:

$$\text{NSRWF}_{q,r,p,y} = [\max(0.001, \text{RTNSAWDS}_{q,r,p,y}) * \text{TLMP}_{y}] / [\sum_{y} \max(0.001, \text{RTNSAWDS}_{q,r,p,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTNSIMBAMT_{q}	$	*Real-Time Non-Spin Imbalance Amount for the QSE*— The total payment or charge to QSE *q* for the Real-Time Non-Spin imbalance for each 15-minute Settlement Interval.
$\text{RTNSAWD}_{q,r}$	MW	*Real Time Non-Spin Award per Resource per QSE* - The Non-Spin amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTNSREV}_{q,r}$	$	*Real-Time Non-Spin Revenue*— The Real-Time Non-Spin revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTNSAWDS}_{q,r,p,y}$	MW	*Real Time Non-Spin Award per Resource per QSE per SCED interval* - The Non-Spin Amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTMCPCNSR}_{q,r}$	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin per Resource per QSE*— The Real-Time MCPC for Non-Spin for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMCPCNSS_{y}	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin per SCED Interval* - The Real-Time MCPC for Non-Spin for the SCED interval *y*.

$PCNSR_{r,\ q,\ DAM}$	MW	*Procured Capacity for Non-Spin per Resource per QSE in DAM*—The Non-Spin capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCNS	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
$RTRDPANSS_{y}$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Non-Spin per SCED interval* - The Real-Time price adder for Non-Spin that captures the impact of reliability deployments on Non-Spin prices for the SCED interval *y*.
$DASANSQ_{q}$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
$NSTP_{q}$	MW	*Trade Purchases for Non-Spin for the QSE*— The trade purchases for QSE *q* for Non-Spin for the Operating Hour.
$NSTS_{q}$	MW	*Trade Sales for Non-Spin for the QSE*— The trade sales for QSE *q* for Non-Spin for the Operating Hour.
$TLMP_{y}$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval y within the Settlement Interval.
$NSRWF_{q,\ r,\ p,\ y}$	none	*Non-Spin Resource Node Weighting Factor per interval* - The Non-Spin Resource weight, based on Non-Spin awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
p	none	A Resource Node Settlement Point.

(2) Non-Spin Only Charge:

$$\mathbf{RTNSOAMT}_{q} = \quad \mathbf{(1/4) * DANSOAWD}_{q} \mathbf{* RTMCPCNS}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$RTNSOAMT_{q}$	$	*Real-Time Non-Spin Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for Non-Spin only award for each 15-minute Settlement Interval.
$DANSOAWD_{q}$	MW	*Day-Ahead Non-Spin Only Award for the QSE*— The Non-Spin only capacity awarded in the DAM to the QSE *q* for the Operating Hour.

RTMCPCNS	\$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
q	none	A QSE.

(3) Non-Spin Trade Overage Charge:

$$\textbf{RTNSTOAMT}_{q} = \quad \textbf{(1/4) * RTNSTO}_{q} \textbf{ * RTMCPCRNS}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTNSTOAMT $_{q}$	\$	*Real-Time Non-Spin Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for Non-Spin trade overages for each 15-minute Settlement Interval.
RTNSTO $_{q}$	MW	*Real-Time Non-Spin Trade Overage for the QSE* — The quantity of submitted Non-Spin trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.
RTMCPCNS	\$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.6 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.6 ERCOT Contingency Reserve Service Payments and Charges

(1) ECRS Imbalance Payment or Charge:

$$\textbf{RTECRIMBAMT}_{q} = \textbf{(-1) * [} \sum_{r} \textbf{[RTECRREV}_{q,\, r} \textbf{ – (1/4) * (PCECRR}_{r,\, q,\, DAM} \textbf{ * RTMCPCECR)] – (1/4) * (DASAECRQ}_{q} \textbf{ * RTMCPCECR) + (1/4) * (ECRTP}_{q} \textbf{ – ECRTS}_{q}\textbf{) * RTMCPCECR]}$$

Where:

$$\textbf{RTECRREV}_{q,\, r} = \quad \textbf{(1/4) * RTECRAWD}_{q,\, r} \textbf{ * RTMCPCECRR}_{q,\, r}$$

$$\textbf{RTMCPCECRR}_{q,\, r} = \sum_{y} \textbf{(ECRRWF}_{q,\, r,\, p,\, y} \textbf{ * (RTMCPCECRS}_{y} \textbf{ + RTRDPAECRS}_{y}\textbf{))}$$

$$\textbf{RTECRAWD}_{q,r} = \sum_{y} \textbf{(RNWF}_{y} \textbf{ * RTECRAWDS}_{q,\, r,\, p,\, y}\textbf{)}$$

Where:

$$\text{ECRRWF}_{q,\,r,\,p,\,y} = [\max(0.001, \text{RTECRAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y}] \,/\, [\sum_{y} \max(0.001, \text{RTECRAWDS}_{q,\,r,\,p,\,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} \,/\, \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTECRIMBAMT_{q}	$	*Real-Time ERCOT Contingency Reserve Service Imbalance Amount for the QSE*— The total payment or charge to QSE *q* for the Real-Time ECRS imbalance for each 15-minute Settlement Interval.
$\text{RTECRAWD}_{q,r}$	MW	*Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE*— The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for 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.
$\text{RTECRREV}_{q,\,r}$	$	*Real-Time ERCOT Contingency Reserve Service Revenue*— The Real-Time ECRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTECRAWDS}_{q,\,r,\,p,\,y}$	MW	*Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE per SCED interval* - The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTMCPCECRR}_{q,\,r}$	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per Resource per QSE* — The Real-Time MCPC for ECRS for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMCPCECRS_{y}	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per SCED Interval* — The Real-Time MCPC for ECRS for the SCED interval *y*.
$\text{PCECRR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per Resource per QSE in DAM*—The ECRS capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service* — The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
RTRDPAECRS_{y}	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for ERCOT Contingency Reserve Service per SCED interval* - The Real-Time price adder for ECRS that captures the impact of reliability deployments on ECRS prices for the SCED interval *y*.

DASAECRQ_{q}	MW	*Day-Ahead Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE*—The self-arranged ECRS quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
ECRTP_{q}	MW	*Trade Purchases for ERCOT Contingency Reserve Service for the QSE*— The trade purchases for QSE *q* for ECRS for the Operating Hour.
ECRTS_{q}	MW	*Trade Sales for ERCOT Contingency Reserve Service for the QSE*— The trade sales for QSE *q* for ECRS for the Operating Hour.
TLMP_{y}	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{ECRRWF}_{q,\,r,\,p,\,y}$	none	*ERCOT Contingency Reserve Service Resource Node Weighting Factor per interval* - The ECRS Resource weight, based on ECRS awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
p	none	A Resource Node Settlement Point.

(2) ECRS Only Charge:

$$\mathbf{RTECROAMT}_{\boldsymbol{q}} = \quad \mathbf{(1/4) * DAECROAWD}_{\boldsymbol{q}} \mathbf{* RTMCPCECR}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTECROAMT_{q}	$	*Real-Time ERCOT Contingency Reserve Service Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for ECRS only awards for each 15-minute Settlement Interval.
DAECROAWD_{q}	MW	*Day-Ahead ERCOT Contingency Service Only Award for the QSE*— The ECRS only capacity awarded in the DAM to the QSE *q* for the Operating Hour.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service* — The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
q	none	A QSE.

(3) ECRS Trade Overage Charge:

$$\mathbf{RTECRTOAMT}_{\boldsymbol{q}} = \quad \mathbf{(1/4) * RTECRTO}_{\boldsymbol{q}} \mathbf{* RTMCPCRECR}$$

The above variables are defined as follows:

Variable	Unit	Description
RTECRTOAMT $_q$	$	*Real-Time ERCOT Contingency Reserve Service Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for ECRS trade overages for each 15-minute Settlement Interval.
RTECRTO $_q$	MW	*Real-Time ERCOT Contingency Reserve Service Trade Overage for the QSE* — The quantity of submitted ECRS trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service* — The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.7 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.7 Real-Time Derated Ancillary Service Capability Payment

(1) If ERCOT manually reduces the amount of an Ancillary Service that may be awarded to a Resource in Real-Time under paragraph (6) of Section 6.4.9.1.1, Ancillary Service Awards, and the reduction reduces the payment the QSE would have received under Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge, the QSE may be eligible for a Real-Time derated Ancillary Service capability payment under this Section.

(2) In order to be eligible for a Real-Time derated Ancillary Service capability payment, the QSE must:

(a) File a timely Settlement and billing dispute, identifying the following items, by Settlement Interval:

(i) Dollar amount and calculation of the estimated Real-Time derated Ancillary Service capability payment;

(ii) The quantity of Ancillary Service awards, by Ancillary Service product, that were not awarded due to ERCOT's manual reduction of the Resource's Ancillary Service capability;

(iii) Any additional revenues earned by the QSE under Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node; and

(iv) Any additional revenues earned by the QSE under Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge.

(b) Have submitted an Ancillary Service Offer for the disputed Settlement Interval(s). The Ancillary Service Offer used to calculate the Real-Time derated Ancillary Service capability payment shall be the most recent offer received by ERCOT effective for the disputed Settlement Interval(s) before ERCOT manually reduced the amount of Ancillary Service to be awarded.

(3) ERCOT shall attempt to validate the calculations provided by the QSE, and may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT's request. Upon determination by ERCOT that no additional supporting documentation or explanation is needed from the disputing QSE, ERCOT shall notify the QSE of its acceptance or rejection of the claim for the Real-Time derated Ancillary Service capability payment within 15 Business Days.

(4) The price used to determine the derated MWs that were not awarded due to the manual reduction shall be the Real-Time MCPC for the Ancillary Service that was reduced.

(5) The amount recoverable under this section shall be capped by the Real-Time MCPC for the Ancillary Service that was reduced, multiplied by the reduced quantity.

(6) The amount recoverable under this Section shall be reduced by any additional revenue received by the QSE, as determined in paragraphs (2)(a)(iii) and (2)(a)(iv) above.

(7) The Real-Time derated Ancillary Service capability payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTDASAMT}_{q} = (-1) * \mathbf{Min}[(\mathbf{RTRUILD}_{q} + \mathbf{RTRDILD}_{q} + \mathbf{RTRRILD}_{q} + \mathbf{RTNSILD}_{q} + \mathbf{RTECRILD}_{q} - \mathbf{RTEIRD}_{q} - \mathbf{RTASIRD}_{q}), \sum_{r} \mathbf{RTDASCAP}_{q,r}]$$

Where:

$$\text{RTDASCAP}_{q,r} = (1/4) * (\text{RTMCPCRU} * \text{RTRUDQ}_{q,r} + \text{RTMCPCRD} * \text{RTRDDQ}_{q,r} + \text{RTMCPCRR} * \text{RTRRDQ}_{q,r} + \text{RTMCPCNS} * \text{RTNSDQ}_{q,r} + \text{RTMCPCECR} * \text{RTECRDQ}_{q,r})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTDASAMT $_{q}$	$	*Real-Time Derated Ancillary Service Amount*—The payment to QSE *q* for amounts recoverable resulting from a manual reduction of Ancillary Services by ERCOT for the 15-minute Settlement Interval.
RTRUILD $_{q}$	$	*Real-Time Derated Regulation Up Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.2,

		Regulation Up Service Payments and Charges, for the 15-minute Settlement Interval.
RTRDILD $_{q}$	$	*Real-Time Derated Regulation Down Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.3, Regulation Down Service Payments and Charges, for the 15-minute Settlement Interval.
RTRRILD $_{q}$	$	*Real-Time Derated Responsive Reserve Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.4, Responsive Reserve Payments and Charges, for the 15-minute Settlement Interval.
RTNSILD $_{q}$	$	*Real-Time Derated Non-Spin Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.5, Non-Spinning Reserve Service Payments and Charges, for the 15-minute Settlement Interval.
RTECRILD $_{q}$	$	*Real-Time Derated ERCOT Contingency Reserve Service Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.6, ERCOT Contingency Reserve Service Payments and Charges, for the 15-minute Settlement Interval.
RTEIRD $_{q}$	$	*Real-Time Energy Imbalance Revenues for Deration*—The additional payments to QSE *q* under Section 6.6.3.1.
RTASIRD $_{q}$	$	*Real-Time Ancillary Service Imbalance Revenues for Deration*—The additional Ancillary Service imbalance payments to QSE *q* for all Ancillary Service products for the 15-minute Settlement Interval.
RTDASCAP $_{q, r}$	$	*Real-Time Derated Ancillary Service Payment Cap*—The amount recoverable for Resource *r* represented by QSE *q,* capped by the Real-Time MCPC for the Ancillary Service product that was derated, multiplied by the quantity by which the Resource's capability to provide the Ancillary Service was reduced for the 15-minute Settlement Interval.
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Regulation Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Regulation Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
RTMCPCRR	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
RTMCPCNS	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service* — The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
RTRUDQ $_{q, r}$	MW	*Real-Time Regulation Up Derated Quantity* - The Reg-Up quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval.
RTRDDQ $_{q, r}$	MW	*Real-Time Regulation Down Derated Quantity* - The Reg-Down quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval.
RTRRDQ $_{q, r}$	MW	*Real-Time Responsive Reserve Derated Quantity* - The RRS quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval.

RTECRDQ $_{q,\,r}$	MW	*Real-Time ERCOT Contingency Reserve Service Derated Quantity* - The ECRS quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval.
RTNSDQ $_{q,\,r}$	MW	*Real-Time Non-Spin Derated Quantity* - The Non-Spin quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval.
q	none	A QSE.
r	none	A Resource.

[NPRR1010: Insert Section 6.7.5.8 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.8 Real-Time Derated Ancillary Service Capability Charge

(1) The total cost for Real-Time derated Ancillary Service payments and charges is allocated to QSEs representing Load based on Load Ratio Share (LRS). The Real-Time derated Ancillary Service Payment allocations to each QSE for a given 15-minute Settlement Interval are calculated as follows:

$$\text{LARTDASAMT}_{q} = (-1) * \text{RTDASAMTTOT} * \text{LRS}_{q}$$

Where:

$$\text{RTDASAMTTOT} = \sum_{q} \text{RTDASAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
LARTDASAMT $_{q}$	$	*Load Allocated Real-Time Derated Ancillary Service Amount per QSE* – The charge to QSE *q* due to a manual reduction of Ancillary Services to be awarded for the 15-minute Settlement Interval.
RTDASAMTTOT	$	*Real-Time Derated Ancillary Service Amount Total* —The total of all payments to all QSEs for amounts recoverable due to an ERCOT issued manual reduction of Ancillary Services to be awarded for the 15-minute Settlement Interval.
RTDASAMT $_{q}$	$	*Real-Time Derated Ancillary Service Amount*—The payment to QSE *q* for amounts recoverable due to an ERCOT issued manual reduction of Ancillary Services to be awarded for the 15-minute Settlement Interval.
LRS $_{q}$	none	*Load Ratio Share per QSE*—The LRS as defined in Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval, for QSE *q* for the 15-minute Settlement Interval.
q	none	A QSE.

6.7.6 Real-Time Ancillary Service Imbalance Revenue Neutrality Allocation

(1) The total cost for Ancillary Service Imbalance payments and charges associated with ORDC and reliability deployments is allocated to the QSEs representing Load based on Load Ratio Share (LRS). The Real-Time Ancillary Service imbalance revenue neutrality allocations to each QSE for a given 15-minute Settlement Interval are calculated as follows:

$$\mathbf{LAASIRNAMT}_{q} = \mathbf{(-1) * [(RTASIAMTTOT + RTRUCRSVAMTTOT) * LRS}_{q}\mathbf{]}$$

$$\mathbf{LARDASIRNAMT}_{q} = \mathbf{(-1) * [(RTRDASIAMTTOT + RTRDRUCRSVAMTTOT) * LRS}_{q}\mathbf{]}$$

Where:

$$\text{RTASIAMTTOT} = \sum_{q} \text{RTASIAMT}_{q}$$

$$\text{RTRUCRSVAMTTOT} = \sum_{q} \text{RTRUCRSVAMT}_{q}$$

$$\text{RTRDASIAMTTOT} = \sum_{q} \text{RTRDASIAMT}_{q}$$

$$\text{RTRDRUCRSVAMTTOT} = \sum_{q} \text{RTRDRUCRSVAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LAASIRNAMT $_{q}$	\$	*Load-Allocated Ancillary Service Imbalance Revenue Neutrality Amount per QSE*—The QSE *q*'s share of the total Real-Time Ancillary Service imbalance revenue neutrality amount associated with ORDC for the 15-minute Settlement Interval.
LARDASIRNAMT $_{q}$	\$	*Load-Allocated Reliability Deployment Ancillary Service Imbalance Revenue Neutrality Amount per QSE*—The QSE *q*'s share of the total Real-Time Ancillary Service imbalance revenue neutrality amount associated with Reliability Deployments for the 15-minute Settlement Interval.
RTASIAMTTOT	\$	*Real-Time Ancillary Service Imbalance Market Total Amount*—The total payment or charge to all QSEs for the Real-Time Ancillary Service imbalance associated with ORDC for each 15-minute Settlement Interval.
RTASIAMT $_{q}$	\$	*Real-Time Ancillary Service Imbalance Amount*—The total payment or charge to QSE *q* for the Real-Time Ancillary Service imbalance associated with ORDC for each 15-minute Settlement Interval.
RTRDASIAMTTOT	\$	*Real-Time Reliability Deployment Ancillary Service Imbalance Market Total Amount*—The total payment or charge to all QSEs for the Real-Time Ancillary Service imbalance associated with Reliability Deployments for each 15-minute Settlement Interval.
RTRDASIAMT $_{q}$	\$	*Real-Time Reliability Deployment Ancillary Service Imbalance Amount*—The total payment or charge to QSE *q* for the Real-Time Ancillary Service

Variable	Unit	Definition
		imbalance associated with Reliability Deployments for each 15-minute Settlement Interval.
RTRUCRSVAMTTOT	$	*Real-Time RUC Ancillary Service Reserve Market Total Amount*—The total payment to all QSEs for the Real-Time RUC Ancillary Service reserve payments associated with ORDC for each 15-minute Settlement Interval.
RTRUCRSVAMT $_q$	$	*Real-Time RUC Ancillary Service Reserve Amount*—The total payment to QSE q for the Real-Time RUC Ancillary Service reserve payment associated with ORDC for each 15-minute Settlement Interval.
RTRDRUCRSVAMTTOT	$	*Real-Time Reliability Deployment RUC Ancillary Service Reserve Market Total Amount*—The total payment |to all QSEs for the Real-Time RUC Ancillary Service Reserve payment as a result of Reliability Deployments for each 15-minute Settlement Interval.
RTRDRUCRSVAMT $_q$	$	*Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount*—The total payment |to QSE q for the Real-Time RUC Ancillary Service Reserve payment as a result of Reliability Deployments for each 15-minute Settlement Interval.
LRS $_q$	none	The LRS calculated for QSE q for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Replace Section 6.7.6 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.6 Real-Time Ancillary Service Revenue Neutrality Allocation

(1) The total cost for Real-Time Ancillary Service payments and charges is allocated to the QSEs representing Load based on Load Ratio Share (LRS). The Real-Time Ancillary Service allocations to each QSE for a given 15-minute Settlement Interval are calculated as follows:

(a) For Reg-Up:

$$\text{LARTRUAMT}_q = (-1) * (\text{RTRUIMBAMTTOT} + \text{RTRUOAMTTOT} + \text{RTRUTOAMTTOT}) * \text{LRS}_q$$

Where:

$$\text{RTRUIMBAMTTOT} = \sum_q (\text{RTRUIMBAMT}_q)$$

$$\text{RTRUOAMTTOT} = \sum_q (\text{RTRUOAMT}_q)$$

$$\text{RTRUTOAMTTOT} = \sum_q (\text{RTRUTOAMT}_q)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTRUAMT $_q$	$	*Load-Allocated Real-Time Reg-Up Amount for the QSE*— The QSE *q*'s share of the total Real-Time Reg-Up amount for the 15-minute Settlement Interval.
RTRUIMBAMT $_q$	$	*Real-Time Reg-Up Imbalance Amount for the QSE* - The total payment or charge to QSE *q* for the Real-Time Reg-Up imbalance for each 15-minute Settlement Interval.
RTRUOAMT $_q$	$	*Real-Time Reg-Up Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Up only awards for each 15-minute Settlement Interval.
RTRUIMBAMTTOT	$	*Real-Time Reg-Up Imbalance Market Total Amount* - The total payment or charge to all QSEs for the Real-Time Reg-Up imbalance for each 15-minute Settlement Interval.
RTRUOAMTTOT	$	*Real-Time Reg-Up Only Market Total Amount* - The total charge to all QSEs in Real-Time for Reg-Up only awards for each 15-minute Settlement Interval.
RTRUTOAMT $_q$	$	*Real-Time Reg-Up Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Up trade overages for each 15-minute Settlement Interval.
RTRUTOAMTTOT	$	*Real-Time Reg-Up Trade Overage Total Amount* — The total charge to all QSEs for Real-Time Reg-Up trade overages for each 15-minute Settlement Interval.
LRS $_q$	none	*Load Ratio Share per QSE*—The LRS as defined in Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval, for QSE *q* for the 15-minute Settlement Interval.
q	none	A QSE.

(b) For Reg-Down:

$$\text{LARTRDAMT}_q = (-1) * (\text{RTRDIMBAMTTOT} + \text{RTRDOAMTTOT} + \text{RTRDTOAMTTOT}) * \text{LRS}_q$$

Where:

$$\text{RTRDIMBAMTTOT} = \sum_q (\text{RTRDIMBAMT}_q)$$

$$\text{RTRDOAMTTOT} = \sum_q (\text{RTRDOAMT}_q)$$

$$\text{RTRDTOAMTTOT} = \sum_q (\text{RTRDTOAMT}_q)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTRDAMT $_q$	$	*Load-Allocated Real-Time Reg-Down Amount for the QSE* — The QSE *q*'s share of the total Real-Time Reg-Down amount for the 15-minute Settlement Interval.

RTRDIMBAMT $_q$	$	*Real-Time Reg-Down Imbalance Amount for the QSE* - The total payment or charge to QSE *q* for the Real-Time Reg-Down imbalance for each 15-minute Settlement Interval.
RTRDOAMT $_q$	$	*Real-Time Reg-Down Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Down only awards for each 15-minute Settlement Interval.
RTRDIMBAMTTOT	$	*Real-Time Reg-Down Imbalance Market Total Amount* - The total payment or charge to all QSEs for the Real-Time Reg-Down imbalance for each 15-minute Settlement Interval.
RTRDOAMTTOT	$	*Real-Time Reg-Down Only Market Total Amount* - The total charge to all QSEs in Real-Time for Reg-Down only awards for each 15-minute Settlement Interval.
RTRDTOAMT $_q$	$	*Real-Time Reg-Down Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for Reg-Down trade overages for each 15-minute Settlement Interval.
RTRDOAMTTOT	$	*Real-Time Reg-Down Trade Overage Total Amount* — The total charge to all QSEs for Real-Time Reg-Down trade overages for each 15-minute Settlement Interval.
LRS $_q$	none	*Load Ratio Share per QSE*—The LRS as defined in Section 6.6.2.2 for QSE *q* for the 15-minute Settlement Interval.
q	none	A QSE.

(c) For Responsive Reserve (RRS):

$$\text{LARTRRAMT}_q = (-1) * (\text{RTRRIMBAMTTOT} + \text{RTRROAMTTOT} + \text{RTRRTOAMTTOT}) * \text{LRS}_q$$

Where:

$$\text{RTRRIMBAMTTOT} = \sum_q (\text{RTRRIMBAMT}_q)$$

$$\text{RTRROAMTTOT} = \sum_q (\text{RTRROAMT}_q)$$

$$\text{RTRRTOAMTTOT} = \sum_q (\text{RTRRTOAMT}_q)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTRRAMT $_q$	$	*Load-Allocated Real-Time Responsive Reserve Amount for the QSE* — The QSE's share of the total Real-Time RRS amount for the 15-minute Settlement Interval.
RTRRIMBAMT $_q$	$	*Real-Time Responsive Reserve Imbalance Amount for the QSE* - The total payment or charge to QSE *q* for the Real-Time RRS imbalance for each 15-minute Settlement Interval.
RTRROAMT $_q$	$	*Real-Time Responsive Reserve Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for RRS only awards for each 15-minute Settlement Interval.

RTRRIMBAMTTOT	$	*Real-Time Responsive Reserve Imbalance Market Total Amount* - The total payment or charge to all QSEs for the Real-Time RRS imbalance for each 15-minute Settlement Interval.
RTRROAMTTOT	$	*Real-Time Responsive Reserve Only Market Total Amount* - The total charge to all QSEs in Real-Time for RRS only awards for each 15-minute Settlement Interval.
RTRRTOAMT $_q$	$	*Real-Time Responsive Reserve Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for RRS trade overages for each 15-minute Settlement Interval.
RTRROAMTTOT	$	*Real-Time Responsive Reserve Trade Overage Total Amount* — The total charge to all QSEs for Real-Time RRS trade overages for each 15-minute Settlement Interval.
LRS $_q$	none	*Load Ratio Share per QSE*—The LRS as defined in Section 6.6.2.2 for QSE *q* for the 15-minute Settlement Interval.
q	none	A QSE.

(d) For Non-Spin:

$$\text{LARTNSAMT}_q = (-1) * (\text{RTNSIMBAMTTOT} + \text{RTNSOAMTTOT} + \text{RTNSTOAMTTOT}) * \text{LRS}_q$$

Where:

$$\text{RTNSIMBAMTTOT} = \sum_q (\text{RTNSIMBAMT}_q)$$

$$\text{RTNSOAMTTOT} = \sum_q (\text{RTNSOAMT}_q)$$

$$\text{RTNSTOAMTTOT} = \sum_q (\text{RTNSTOAMT}_q)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTNSAMT $_q$	$	*Load-Allocated Real-Time Non-Spin Amount for the QSE* — The QSE's share of the total Real-Time Non-Spin amount for the 15-minute Settlement Interval.
RTNSIMBAMT $_q$	$	*Real-Time Non-Spin Imbalance Amount for the QSE* - The total payment or charge to QSE *q* for the Real-Time Non-Spin imbalance for each 15-minute Settlement Interval.
RTNSOAMT $_q$	$	*Real-Time Non-Spin Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for Non-Spin only awards for each 15-minute Settlement Interval.
RTNSIMBAMTTOT	$	*Real-Time Non-Spin Imbalance Market Total Amount* - The total payment or charge to all QSEs for the Real-Time Non-Spin imbalance for each 15-minute Settlement Interval.
RTNSOAMTTOT	$	*Real-Time Non-Spin Only Market Total Amount* - The total charge to all QSEs in Real-Time for Non-Spin only awards for each 15-minute Settlement Interval.

RTNSTOAMT_q	$	*Real-Time Non-Spin Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for Non-Spin trade overages for each 15-minute Settlement Interval.
RTNSOAMTTOT	$	*Real-Time Non-Spin Trade Overage Total Amount* — The total charge to all QSEs for Real-Time Non-Spin trade overages for each 15-minute Settlement Interval.
LRS_q	none	*Load Ratio Share per QSE*—The LRS as defined in Section 6.6.2.2 for QSE *q* for the 15-minute Settlement Interval.
q	none	A QSE.

(e) For ERCOT Contingency Reserve Service (ECRS):

$$\text{LARTECRAMT}_q = (-1) * (\text{RTECRIMBAMTTOT} + \text{RTECROAMTTOT} + \text{RTECRTOAMTTOT}) * \text{LRS}_q$$

Where:

$$\text{RTECRIMBAMTTOT} = \sum_q (\text{RTECRIMBAMT}_q)$$

$$\text{RTECROAMTTOT} = \sum_q (\text{RTECROAMT}_q)$$

$$\text{RTECRTOAMTTOT} = \sum_q (\text{RTECRTOAMT}_q)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTECRAMT_q	$	*Load-Allocated Real-Time ERCOT Contingency Reserve Service Amount for the QSE* - The QSE *q*'s share of the total Real-Time ECRS amount for the 15-minute Settlement Interval.
RTECRIMBAMT_q	$	*Real-Time ERCOT Contingency Reserve Service Imbalance Amount for the QSE* - The total payment or charge to QSE *q* for the Real-Time ECRS imbalance for each 15-minute Settlement Interval.
RTECROAMT_q	$	*Real-Time ERCOT Contingency Reserve Service Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for ECRS only awards for each 15-minute Settlement Interval.
RTECRIMBAMTTOT	$	*Real-Time ERCOT Contingency Reserve Service Imbalance Market Total Amount* - The total payment or charge to all QSEs for the Real-Time ECRS imbalance for each 15-minute Settlement Interval.
RTECROAMTTOT	$	*Real-Time ERCOT Contingency Reserve Service Only Market Total Amount* - The total charge to all QSEs in Real-Time for ECRS only awards for each 15-minute Settlement Interval.
RTECRTOAMT_q	$	*Real-Time ERCOT Contingency Reserve Service Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for ECRS trade overages for each 15-minute Settlement Interval.
RTECROAMTTOT	$	*Real-Time ERCOT Contingency Reserve Service Trade Overage Total Amount* — The total charge to all QSEs for Real-Time ECRS trade overages for each 15-minute Settlement Interval.

LRS $_q$	none	*Load Ratio Share per QSE*—The LRS as defined in Section 6.6.2.2 for QSE *q* for the 15-minute Settlement Interval.
q	none	A QSE.

6.7.7 *Adjustments to Net Cost Allocations for Real-Time Ancillary Services*

If ERCOT assigns Ancillary Service during a Watch, the incremental cost for assigned Ancillary Service is calculated in this section.

(1) For Reg-Up, if applicable:

(a) The total costs for Reg-Up for a given Operating Hour during a Watch is calculated as follows:

$$\mathbf{ARUCOSTTOT = (-1) * RTAURUAMTTOT + RUCOSTTOT}$$

Where:

Total payment of Real-Time Ancillary Service Assignment procured capacity for un-deployed Reg-Up

$$\text{RTAURUAMTTOT} = \sum_{q}\sum_{r}\sum_{p}\sum_{i=1}^{4} \text{RTAURUAMT}_{q,r,p,i}$$

The above variables are defined as follows:

Variable	Unit	Description
ARUCOSTTOT	\$	*Reg-Up Cost Total*—The total costs for Reg-Up that includes costs of assigned Ancillary Service during a Watch for the hour.
RUCOSTTOT	\$	*Reg-Up Cost Total*—The net total costs for Reg-Up for the hour.
RTAURUAMTTOT	\$	*Real-Time Assigned Un-Deployed Regulation Up Payment Amount Total for all QSEs*—The payments to all QSEs for the Real-Time un-deployed Reg-Up Ancillary Service Assignment for the hour.
RTAURUAMT $_{q,r,p,i}$	\$	*Real-Time Assigned Un-Deployed Regulation Up Payment Amount per QSE*—The payment to QSE *q* for a Real-Time un-deployed Reg-Up Ancillary Service Assignment to Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	A Generation Resource that was allocated Reg-Up Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated Reg-Up Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.

(b) Each QSE's share of the total costs for Reg-Up for the Operating Hour, including Ancillary Service costs assigned during a Watch is calculated as follows:

$$\textbf{ARUCOST}_{q} = \textbf{ARUPR} * \textbf{ARUQ}_{q}$$

Where:

$$\text{ARUPR} = \text{ARUCOSTTOT} / \text{ARUQTOT}$$

$$\text{ARUQTOT} = \sum_{q} \text{ARUQ}_{q}$$

$$\text{ARUQ}_{q} = \text{ARUO}_{q} - \text{SARUQ}_{q}$$

$$\text{ARUO}_{q} = \text{WAURUTOT} * \text{HLRS}_{q} + \text{RUO}_{q}$$

$$\text{WAURUTOT} = \sum_{q} \sum_{r} \sum_{P} \text{RTAURUR}_{q,r,p}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
ARUCOST_{q}	$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up that includes costs of assigned Ancillary Service during a Watch, for the hour.
ARUPR	$/MW per hour	*Reg-Up Price*—The price for Reg-Up calculated based on the net total costs for Reg-Up, for the hour.
ARUCOSTTOT	$	*Reg-Up Cost Total*—The total costs for Reg-Up that includes costs of assigned Ancillary Service during a Watch for the hour.
ARUQTOT	MW	*Reg-Up Quantity Total*—The sum of every QSE's portion of its Ancillary Service Obligation that is not self-arranged in either DAM or any SASM that includes assigned Ancillary Service, during a Watch, for the hour.
ARUQ_{q}	MW	*Reg-Up Quantity per QSE*—The portion of QSE *q*'s total Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, that includes assigned Ancillary Service, during a Watch for the hour.
WAURUTOT	MW	*Watch Assigned Un-Deployed Regulation Up Quantity*- The total market wide quantity of un-deployed Reg-Up Ancillary Service Assignment for the hour.
$\text{RTAURUR}_{q,r}$	MW	*Real-Time Assigned Un-Deployed Regulation Up Quantity per Resource per QSE* - The quantity of un-deployed Reg-Up Ancillary Service Assignment to a QSE *q* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
ARUO_{q}	MW	*Reg-Up Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour during a Watch.
RUO_{q}	MW	*Reg-Up Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
HLRS_{q}	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
SARUQ_{q}	MW	*Total Self-Arranged Reg-Up Quantity per QSE for all markets*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.

r	none	A Generation Resource that was allocated Reg-Up Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated Reg-Up Ancillary Service Assignment by the QSE.

(c) The incremental cost to each QSE's for assigned Reg-Up for the Operating Hour, is calculated as follows:

$$\mathbf{NETARTRUAMT}_{q} = \mathbf{ARUCOST}_{q} - \mathbf{RUCOST}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
NETARTRUAMT $_{q}$	\$	*Real-Time Reg-Up Amount per QSE*—The net adjustment to QSE *q*'s share of the costs for assigned Reg-Up, for the hour.
ARUCOST $_{q}$	\$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up that includes costs of assigned Ancillary Service during a Watch, for the hour.
RUCOST $_{q}$	\$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up, for the hour.
q	none	A QSE.

(2) For RRS, if applicable:

(a) The total costs for RRS for a given Operating Hour during a Watch is calculated as follows:

$$\mathbf{ARRCOSTTOT} = \mathbf{(-1) * RTAURRAMTTOT + RRCOSTTOT}$$

Where:

Total payment of Real-Time Ancillary Service Assignment procured capacity for un-deployed RRS

$$\text{RTAURRAMTTOT} = \sum_{q} \sum_{r} \sum_{p} \sum_{i=1}^{4} \text{RTAURRAMT}_{q,\,r,\,p,\,i}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
ARRCOSTTOT	\$	*Responsive Reserve Cost Total*—The net total costs for RRS that includes costs of assigned Ancillary Service during a Watch for the hour.
RRCOSTTOT	\$	*Responsive Reserve Cost Total*—The net total costs for RRS for the hour.
RTAURRAMTTOT	\$	*Real-Time Assigned Un-Deployed Responsive Reserve Payment Amount Total for all QSEs* - The payments to all QSEs for the Real-Time un-deployed RRS Ancillary Service Assignment for the hour.
RTAURRAMT $_{q,\,r,p,i}$	\$	*Real-Time Assigned Un-Deployed Responsive Reserve Payment Amount per QSE* - The payment to QSE *q* for a Real-Time un-deployed RRS Ancillary Service Assignment to Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*.

q	none	A QSE.
r	none	A Generation Resource that was allocated RRS Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated RRS Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.

(b) Each QSE's share of the net total costs for RRS for the Operating Hour, including Ancillary Service costs assigned during a Watch is calculated as follows:

$$\mathbf{ARRCOST}_{\boldsymbol{q}} = \mathbf{ARRPR * ARRQ}_{\boldsymbol{q}}$$

Where:

$$\text{ARRPR} = \text{ARRCOSTTOT / ARRQTOT}$$

$$\text{ARRQTOT} = \sum_{q} \text{ARRQ}_{q}$$

$$\text{ARRQ}_{q} = \text{ARRO}_{q} - \text{SARRQ}_{q}$$

$$\text{ARRO}_{q} = \text{WAURRTOT * HLRS}_{q} + \text{RRO}_{q}$$

$$\text{WAURRTOT} = \sum_{q} \sum_{r} \sum_{P} \text{RTAURRR}_{q,\,r,\,p}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
ARRCOST_{q}	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for RRS, that includes costs of assigned Ancillary Service during a Watch for the hour.
ARRPR	$/MW per hour	*Responsive Reserve Price*—The price for RRS calculated based on the net total costs for RRS that includes costs of assigned Ancillary Service during a Watch for the hour.
ARRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for RRS that includes costs of assigned Ancillary Service during a Watch for the hour.
ARRQTOT	MW	*Responsive Reserve Quantity Total*—The sum of every QSE's portion of its Ancillary Service Obligation that is not self-arranged in either DAM or any SASM that includes assigned Ancillary Service, during a Watch,, for the hour.
WAURRTOT	MW	*Watch Assigned Un-Deployed Responsive Reserve Quantity*—The total market wide quantity of un-deployed RRS Ancillary Service Assignment for the hour.
$\text{RTAURRR}_{q,r}$	MW	*Real-Time Assigned Un-Deployed Responsive Reserve Quantity per Resource per QSE*—The quantity of un-deployed RRS Ancillary Service Assignment to a QSE *q* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

ARRQ $_q$	MW	*Responsive Reserve Quantity per QSE*—The portion of QSE *q*'s Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
ARRO $_q$	MW	*Responsive Reserve Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
RRO $_q$	MW	*Responsive Reserve Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
HLRS $_q$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
SARRQ $_q$	MW	*Total Self-Arranged Responsive Reserve Quantity per QSE for all markets*—The sum of all self-arranged RRS quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
r	none	A Generation Resource that was allocated RRS Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated RRS Ancillary Service Assignment by the QSE.

(c) The incremental cost to each QSE's for assigned RRS for the Operating Hour, is calculated as follows:

$$\mathbf{NETARTRRAMT}_{q} = \mathbf{ARRCOST}_{q} - \mathbf{RRCOST}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
NETARTRRAMT $_q$	$	*Real-Time Responsive Reserve Amount per QSE*—The net adjustment to QSE *q*'s share of the costs for assigned RRS, for the hour.
RRCOST $_q$	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for RRS, for the hour.
ARRCOST $_q$	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for RRS that includes costs of assigned Ancillary Service during a Watch, for the hour.
q	none	A QSE.

[NPRR863: Insert paragraph (3) below upon system implementation:]

(3) For ECRS, if applicable:

(a) The total costs for ECRS for a given Operating Hour during a Watch is calculated as follows:

$$\mathbf{AECRCOSTTOT} = \mathbf{(-1) * RTAUECRAMTTOT + ECRCOSTTOT}$$

Where:

Total payment of Real-Time Ancillary Service Assignment procured capacity for un-deployed ECRS

$$\text{RTAUECRAMTTOT} = \sum_{q} \sum_{r} \sum_{p} \sum_{i=1}^{4} \text{RTAUECRAMT}_{q,\,r,\,p,\,i}$$

The above variables are defined as follows:

Variable	Unit	Description
AECRCOSTTOT	$	*ERCOT Contingency Reserve Service Cost Total*—The net total costs for ECRS that includes costs of assigned Ancillary Service during a Watch for the hour.
ECRCOSTTOT	$	*ERCOT Contingency Reserve Service Cost Total*—The net total costs for ECRS for the hour.
RTAUECRAMTTOT	$	*Real-Time Assigned Un-Deployed ERCOT Contingency Reserve Service Payment Amount Total for all QSEs* - The payments to all QSEs for the Real-Time un-deployed ECRS Ancillary Service Assignment for the hour.
$\text{RTAUECRAMT}_{q,\,r,\,p,\,i}$	$	*Real-Time Assigned Un-Deployed ERCOT Contingency Reserve Service Payment Amount per QSE* - The payment to QSE *q* for a Real-Time un-deployed ECRS Ancillary Service Assignment to Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	A Generation Resource that was allocated ECRS Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated ECRS Ancillary Service Assignment by the QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.

(b) Each QSE's share of the net total costs for ECRS for the Operating Hour, including Ancillary Service costs assigned during a Watch is calculated as follows:

$$\mathbf{AECRCOST}_{q} = \mathbf{AECRPR * AECRQ}_{q}$$

Where:

$$\text{AECRPR} = \text{AECRCOSTTOT / AECRQTOT}$$

$$\text{AECRQTOT} = \sum_{q} \text{AECRQ}_{q}$$

$$\text{AECRQ}_{q} = \text{AECRO}_{q} - \text{SAECRQ}_{q}$$

$$\text{AECRO}_{q} = \text{WAUECRTOT * HLRS}_{q} + \text{ECRO}_{q}$$

$$\text{WAUECRTOT} = \sum_{q} \sum_{r} \sum_{P} \text{RTAUECRR}_{q,\,r,\,p}$$

The above variables are defined as follows:

Variable	Unit	Description

AECRCOST $_{q}$	$	*ERCOT Contingency Reserve Service Cost per QSE*—QSE *q*'s share of the net total costs for ECRS, that includes costs of assigned Ancillary Service during a Watch for the hour.
AECRPR	$/MW per hour	*ERCOT Contingency Reserve Service Price*—The price for ECRS calculated based on the net total costs for ECRS that includes costs of assigned Ancillary Service during a Watch for the hour.
AECRCOSTTOT	$	*ERCOT Contingency Reserve Service Cost Total*—The net total costs for ECRS that includes costs of assigned Ancillary Service during a Watch for the hour.
AECRQTOT	MW	*ERCOT Contingency Reserve Service Quantity Total*—The sum of every QSE's portion of its Ancillary Service Obligation that is not self-arranged in either DAM or any SASM that includes assigned Ancillary Service, during a Watch, for the hour.
WAUECRTOT	MW	*Watch Assigned Un-Deployed ERCOT Contingency Reserve Service Quantity*—The total market wide quantity of un-deployed ECRS Ancillary Service Assignment for the hour.
RTAUECRR $_{q,\ r}$	MW	*Real-Time Assigned Un-Deployed ERCOT Contingency Reserve Service Quantity per Resource per QSE*—The quantity of un-deployed ECRS Ancillary Service Assignment to a QSE *q* for Resource *r* for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
AECRQ $_{q}$	MW	*ERCOT Contingency Reserve Service Quantity per QSE*—The portion of QSE *q*'s Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
AECRO $_{q}$	MW	*ERCOT Contingency Reserve Service Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
ECRO $_{q}$	MW	*ERCOT Contingency Reserve Service Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
HLRS $_{q}$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
SAECRQ $_{q}$	MW	*Total Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE for all markets*—The sum of all self-arranged ECRS quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
r	none	A Generation Resource that was allocated ECRS Ancillary Service Assignment by the QSE.
p	none	A Settlement Point for the Resource Node that was allocated ECRS Ancillary Service Assignment by the QSE.

(c) The incremental cost to each QSE's for assigned ECRS for the Operating Hour, is calculated as follows:

$$\mathbf{NETARTECRAMT}_{q} = \mathbf{AECRCOST}_{q} - \mathbf{ECRCOST}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
NETARTECRAMT $_{q}$	$	*Real-Time ERCOT Contingency Reserve Service Amount per QSE*—The net adjustment to QSE *q*'s share of the costs for assigned ECRS, for the hour.

ECRCOST $_q$	$	*ERCOT Contingency Reserve Service Cost per QSE*—QSE *q*'s share of the net total costs for ECRS, for the hour.
AECRCOST $_q$	$	*ERCOT Contingency Reserve Service Cost per QSE*—QSE *q*'s share of the net total costs for ECRS that includes costs of assigned Ancillary Service during a Watch, for the hour.
q	none	A QSE.

[NPRR1010: Delete Section 6.7.7 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.8 Settlement for Operating Losses During an LCAP Effective Period

6.8.1 Determination of Operating Losses During an LCAP Effective Period

(1) In order for a Qualified Scheduling Entity (QSE) that represents a Generation Resource or Energy Storage Resource (ESR) to recover actual marginal costs for operating losses during a Low System-Wide Offer Cap (LCAP) Effective Period, and incurred as calculated in Section 6.8.2, Recovery of Operating Losses During an LCAP Effective Period, the QSE shall timely submit a Settlement and billing dispute for each affected Operating Day, consistent with the dispute process described in Section 9.14, Settlement and Billing Dispute Process. The QSE shall also submit, through the Settlement and billing dispute process, and within 60 days of the issuance of a Real-Time Market (RTM) Initial Statement for an Operating Day, the following information:

(a) For a Generation Resource:

(i) All fuel purchases used to determine the weighted average fuel price included in the calculation of the actual marginal operating fuel cost component, for the Generation Resource, for the 15-minute Settlement Interval within the Operating Day.

(b) For an ESR:

(i) The actual variable O&M rate incurred during the LCAP Effective Period in lieu of the Standard Operations and Maintenance Cost (STOM) defined in Section 6.8.2; and

(ii) The average electricity cost incurred to charge the ESR for the amount of discharge during the LCAP Effective Period.

(c) An attestation signed by an officer or executive with authority to bind the QSE stating that the information contained in the Settlement and billing dispute is accurate and that fixed costs (fees, penalties, and similar non-gas costs) were not included in the calculation of the weighted average fuel price.

(2) The calculation of operating losses under Section 6.8.2 applies only when the Real-Time Settlement Point Price for the Resource is equal to or exceeds the LCAP or when the Resource's Energy Offer Curve is at the LCAP and the Resource receives a Dispatch Instruction or a Base Point above its Low Sustained Limit (LSL).

(3) Fuel prices may include all variable costs associated with the purchase, transportation, and storage of fuel.

(4) ERCOT will consider the documentation provided by the QSE in order to determine the weighted average fuel price for a Generation Resource or the average fuel cost for an ESR during an LCAP Effective Period.

(5) For purposes of determining operating losses during an LCAP Effective Period, ERCOT may request additional information, documentation, or clarification from the QSE. A QSE shall respond to any such request within ten Business Days.

6.8.2 Recovery of Operating Losses During an LCAP Effective Period

(1) ERCOT shall calculate the recovery of operating losses during an LCAP Effective Period with the actual marginal costs that exceed LCAP revenues in accordance with this Section.

(2) The actual marginal cost (AMC) and marginal energy production (MEP) used to calculate operating losses (OPL) for a Combined Cycle Train are the AMC and MEP that correspond to the Combined Cycle Generation Resource, within a Combined Cycle Train, that operates in Real-Time for the 15-minute Settlement Interval.

(3) Payment for operating losses during an LCAP Effective Period is calculated as follows:

$$\mathbf{OPLPAMT}_{q,r,i} = \mathbf{(-1) * (OPL}_{q,r,i} + \mathbf{ADJOPL}_{q,r,i}\mathbf{)}$$

Where,

For the Generation Resource:

$$\text{OPL}_{q,r,i} = \text{Max}(0, (\text{AMC}_{q,r,i} - \text{Max}(\text{LCAP}, \text{RTSPP}_{p,i})) * \text{Min}(\text{RTMG}_{q,r,i}, \text{MEP}_{q,r,i}))$$

If ERCOT approved verifiable costs for the Generation Resource:

$$\text{AMC}_{q,r,i} = \text{AHR}_{q,r,i} * \text{WAFP}_{q,r,i} + \text{ROM}_{q,r}$$

$$\text{MEP}_{q,r,i} = \text{AMF}_{q,r,i} / \text{AHR}_{q,r,i}$$

Otherwise,

$$\text{AMC}_{q,r,i} = \text{PAHR}_{q,r,i} * \text{WAFP}_{q,r,i} + \text{STOM}_{rc}$$

$$\text{MEP}_{q,r,i} = \text{AMF}_{q,r,i} / \text{PAHR}_{q,r,i}$$

For ESRs:

$$OPL_{q,\,r,\,i} = \text{Max}(0, (AMC_{q,\,r,\,i} - \text{Max}(LCAP, RTSPP_{p,\,i})) * RTMG_{q,\,r,\,i})$$

Where,

$$AMC_{q,\,r,\,i} = AFC_{q,\,r,\,i} + STOM_{rc}$$

The above variables are defined as follows:

Variable	Unit	Definition
$OPLPAMT_{q,\,r,\,i}$	$	*Operating Losses Payment Amount* – The operating losses payment to the QSE *q,* for Resource *r*, for the 15-minute Settlement Interval *i* within the Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$OPL_{q,\,r,\,i}$	$	*Operating Losses* — The operating losses for Resource *r*, represented by QSE *q,* for the 15-minute Settlement Interval *i* within the Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$ADJOPL_{q,\,r,\,i}$	$	*Operating Losses Adjustment* — The adjustment to the operating losses for Resource *r*, represented by QSE *q,* for the 15-minute Settlement Interval *i* within the Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$WAFP_{q,\,r,\,i}$	$/MMBtu	*Weighted Average Fuel Price*—The volume-weighted average price of fuel submitted to ERCOT for the LCAP Effective Period for a specific Resource *r,* represented by QSE *q,* and specific 15-minute Settlement Interval *i* within the Operating Day. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$AMC_{q,\,r,\,i}$	$/MWh	*Actual Marginal Cost* – The actual marginal costs for Resource *r* represented by QSE *q* for the 15-minute Settlement Interval *i* within the Operating Day. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
LCAP	$/MWh	*Low System Wide Offer Cap* – The value set per paragraph (1) of Section 4.4.11, System-Wide Offer Caps.
$ROM_{q,\,r}$	$/MWh	*Raw Verifiable Operations and Maintenance Cost Above LSL* – The raw verifiable O&M cost for the Resource *r* represented by QSE *q* for operations above LSL. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$AMF_{q,\,r,\,i}$	MMBtu	*Actual Marginal Fuel per QSE per Resource* - The actual marginal purchased and delivered fuel for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval *i* within the Operating Day. The AMF represents only the fuel used to calculate the weighted average fuel price, WAFP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. For Resources that are granted a dispute under Section 9.14.7, Disputes for RUC Make-Whole Payment for Fuel Costs, the actual marginal purchased and delivered fuel shall include only fuel for operations above LSL.

Variable	Unit	Definition
STOM $_{rc}$	$/MWh	*Standard Operations and Maintenance Cost* – The standard O&M cost for the Resource category *rc* for operations above LSL, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs. For an ESR, STOM shall be set at $0.3/MWh. ***[NPRR1086: Replace the definition above with the following upon system implementation of NPRR1029:]*** *Standard Operations and Maintenance Cost* – The standard O&M cost for the Resource category *rc* for operations above LSL, shall be set to the minimum energy variable O&M costs, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs. For an ESR, STOM shall be set at $0.3/MWh and for a DC-Coupled Resource, the value shall be set at $4.40/MWh.
RTSPP $_{p,\ i}$	$/MWh	*Real-Time Settlement Point Price* - The Real-Time Settlement Point Price at the Settlement Point *p,* for the 15-minute Settlement Interval *i.*
AFC $_{q,\ r,\ i}$	$/MWh	*Average Fuel Cost per Resource* —The average electricity cost used to charge the ESR *r* represented by QSE *q* applicable to the energy discharge for the 15-minute Settlement Interval *i* within the Operating Day.
AHR $_{q,\ r,\ i}$	MMBtu / MWh	*Average Heat Rate per Resource* – The verifiable average heat rate for the Resource *r* represented by QSE *q*, for operating levels between LSL and High Sustained Limit (HSL), for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
PAHR $_{q,\ r,\ i}$	MMBtu / MWh	*Proxy Average Heat Rate* – The proxy average heat rate for the Resource *r,* represented by QSE *q*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMG $_{q,\ r,\ i}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval by hour*—The Real-Time energy from Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train. For Resources that are granted a dispute under Section 9.14.7, the Real-Time energy represents the energy produced for operations above LSL.
MEP $_{q,\ r,\ i}$	MWh	*Marginal Energy Production per QSE per Resource by Settlement Interval* — The calculated marginal generation of Resource *r* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
q	None	A QSE.
r	None	A Generation Resource or ESR.
i	None	A 15-minute Settlement Interval within the Operating Day during an LCAP Effective Period.
rc	None	A Resource category

(2) The total compensation to each QSE for operating losses during an LCAP Effective Period for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{OPLPAMTQSETOT}_{q} \quad = \quad \sum_{r} \mathbf{OPLPAMT}_{q, r, i}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\mathrm{OPLPAMTQSETOT}_{q}$	$	*Total Operating Losses Payment Amount per QSE* – The total operating losses payment to the QSE *q*, for all Resources, for the 15-minute Settlement Interval within the Operating Day.
$\mathrm{OPLPAMT}_{q, r, i}$	$	*Operating Losses Payment Amount* – The operating losses payment to the QSE *q*, for Resource *r*, for the 15-minute Settlement Interval *i* within the Operating Day. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A Generation Resource or ESR.
i	none	A 15-minute Settlement Interval within the Operating Day during an LCAP Effective Period.

6.8.3 Charges for Operating Losses During an LCAP Effective Period

(1) All QSEs that were capacity-short in a Settlement Interval for which actual marginal costs above the LCAP are recovered will be charged for that shortage, as described in Section 6.8.3.1, Charges for Capacity Shortfalls During an LCAP Effective Period. If revenues from the charges under Section 6.8.3.1 are not enough to cover all actual marginal costs above the LCAP for a Settlement Interval, then the difference will be uplifted to all QSEs on a Load Ratio Share (LRS) basis, as described in Section 6.8.3.2, Uplift Charges for an LCAP Effective Period.

6.8.3.1 Charges for Capacity Shortfalls During an LCAP Effective Period

(1) The dollar amount charged to each QSE due to capacity shortfalls for any Settlement Intervals in an LCAP Effective Period is calculated as follows:

$$\mathbf{LCAPCSAMT}_{i, q} = \mathbf{(-1) * Max\ [(LCAPSFRS}_{i, q}\ \mathbf{*\ OPLPAMTTOT}_{i}\mathbf{),}\ \mathbf{(((1/4) * LCAPSF}_{i, q}\mathbf{) * OPLPAMTTOT}_{i}\ \mathbf{/\ OPLCAPTOT}_{i}\mathbf{)]}$$

Where:

$$\mathrm{OPLPAMTTOT}_{i} = \sum_{q} \mathrm{OPLPAMTQSETOT}_{i, q}$$

$$\mathrm{OPLCAPTOT}_{i} = \sum_{q} \sum_{r} \mathrm{RTMG}_{q, r, i}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{LCAPCSAMT}_{i,q}$	$	*LCAP Capacity-Short Amount*—The charge to a QSE *q*, due to capacity shortfall for an LCAP Effective Period, for the 15-minute Settlement Interval *i*.
$\text{OPLPAMTQSETOT}_{i,q}$	$	*Total Operating Losses Payment Amount per QSE* – The total operating losses payment to the QSE *q*, for all Resources, for the 15-minute settlement interval *i* within the Operating Day.
OPLPAMTTOT_{i}	$	*Total Operating Losses Payment Amount* – The sum of Operating Losses Payments to all QSEs, for the 15-minute Settlement Interval *i*.
$\text{LCAPSFRS}_{i,q}$	none	*LCAP Effective Period Shortfall Ratio Share*—The ratio of the QSE *q*'s capacity shortfall to the sum of all QSEs' capacity shortfalls for an LCAP Effective Period for the 15-minute Settlement Interval *i*. See Section 6.8.3.1.1, Capacity Shortfall Ratio Share for an LCAP Effective Period.
$\text{LCAPSF}_{i,q}$	MW	*LCAP Shortfall*—The QSE *q*'s capacity shortfall for an LCAP Effective Period for the 15-minute Settlement Interval *i*. See formula in Section 6.8.3.1.1.
OPLCAPTOT_{i}	MWh	*Operating Loss Capacity Total*—The sum of the Real-Time Metered Generation (RTMG) of all Resources compensated for an LCAP Effective Period for the 15-minute Settlement Interval *i*.
$\text{RTMG}_{q,r,i}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval by hour*—The Real-Time energy from Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train. For Resources that are granted a dispute under Section 9.14.7, Disputes for RUC Make-Whole Payment for Fuel Costs, the Real-Time energy represents the energy produced for operations above LSL.
i	none	A 15-minute Settlement Interval.
q	none	A QSE.
r	none	A Generation Resource or ESR that is compensated during an LCAP Effective Period for the hour that includes the Settlement Interval *i* .

6.8.3.1.1 Capacity Shortfall Ratio Share for an LCAP Effective Period

(1) 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.

(2) The capacity shortfall ratio share of a specific QSE for an LCAP Effective Period is calculated, for a 15-minute Settlement Interval, as follows:

$$\mathbf{LCAPSFRS}_{i,q} = \mathbf{LCAPSF}_{i,q} \,/\, \mathbf{LCAPSFTOT}_{i}$$

Where:

$$\textbf{LCAPSFTOT}_{\textbf{\textit{i}}} = \sum_{q} \textbf{LCAPSF}_{\textbf{\textit{i, q}}}$$

(3) The LCAP Shortfall in MW for a QSE for the 15-minute Settlement Interval is:

$$\textbf{LCAPSF}_{\textbf{\textit{i, q}}} = \textbf{Max (0, ((}\sum_{p} \textbf{RTAML}_{\textbf{\textit{q, p, i}}}\textbf{) *4) – LCAPCAP}_{\textbf{\textit{q, i}}}\textbf{)}$$

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

$$\textbf{LCAPCAP}_{\textbf{\textit{i, q}}} = \sum_{r} \textbf{LCAPHASLADJ}_{\textbf{\textit{q, r, h}}} + \textbf{(RUCCPADJ}_{\textbf{\textit{q, h}}} – \textbf{RUCCSADJ}_{\textbf{\textit{q, h}}}\textbf{)} + \textbf{(}\sum_{p} \textbf{DAEP}_{\textbf{\textit{q, p, h}}} – \sum_{p} \textbf{DAES}_{\textbf{\textit{q, p, h}}}\textbf{)} + \textbf{(}\sum_{p} \textbf{RTQQEPADJ}_{\textbf{\textit{q, p, i}}} – \sum_{p} \textbf{RTQQESADJ}_{\textbf{\textit{q, p, i}}}\textbf{)} + \sum_{p} \textbf{DCIMPADJ}_{\textbf{\textit{q, p, i}}}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LCAPSFRS $_{i,\ q}$	none	*LCAP Effective Period Shortfall Ratio Share*—The ratio of the QSE *q*'s capacity shortfall to the sum of all QSEs' capacity shortfalls for an LCAP Effective Period for the 15-minute Settlement Interval *i*.
LCAPSF $_{i,\ q}$	MW	*LCAP Shortfall*—The QSE *q*'s capacity shortfall for an LCAP Effective Period for the 15-minute Settlement Interval *i*.
LCAPSFTOT $_{i}$	MW	*LCAP Shortfall Total*—The sum of all QSEs' capacity shortfalls, for an LCAP Effective Period for a 15-minute Settlement Interval *i*.
LCAPCAP $_{q,\ i}$	MW	*LCAP Capacity at Adjustment Period*—The QSE *q*'s Adjustment Period calculated capacity 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*.
DCIMPADJ $_{q,\ p,\ i}$	MW	*DC Tie 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*.
LCAPHASLADJ $_{q,\ r,\ h}$	MW	*LCAP Effective Period High Ancillary Services Limit at Adjustment Period*—The HASL of Resource *r,* represented by the QSE *q*, according to the Adjustment Period COP and Trades 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.
RUCCPADJ $_{q,\ h}$	MW	*RUC Capacity Purchase at Adjustment Period*—The QSE *q*'s capacity purchase, according to the Adjustment Period 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 snapshot for the hour *h* that includes the 15-minute Settlement Interval.

Variable	Unit	Definition
$\text{DAEP}_{q,\,p,\,h}$	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.
$\text{DAES}_{q,\,p,\,h}$	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.
$\text{RTQQEPADJ}_{q,\,p,\,i}$	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*, according to the Adjustment Period snapshot.
$\text{RTQQESADJ}_{q,\,p,\,i}$	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*, according to the Adjustment Period snapshot.
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 Adjustment Period snapshot; 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 Reliability Unit Commitment (RUC) instruction for an actual or anticipated Energy Emergency Alert (EEA) condition. If the Settlement Interval is a Reliability Unit Commitment for Additional Capacity (RUCAC)-Interval, *r* represents the Combined Cycle Generation Resource that was QSE-committed at the time the RUCAC was issued.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.

6.8.3.2 Uplift Charges for an LCAP Effective Period

(1) If the revenues from the charges under Section 6.8.3.1, Charges for Capacity Shortfalls During an LCAP Effective Period, are not enough to cover all LCAP Effective Period payments, for a 15-minute Settlement Interval, then the difference will be uplifted to all QSEs on an LRS basis as an LCAP Effective Period Uplift Charge, calculated as follows:

$$\mathbf{LALCAPAMT}_{\boldsymbol{q,\,i}} = \mathbf{(-1) * [OPLPAMTTOT}_{\boldsymbol{i}} \mathbf{+ LCAPCSAMTTOT}_{\boldsymbol{i}}\mathbf{] * LRS}_{\boldsymbol{q,\,i}}$$

Where:

$$\text{OPLPAMTTOT}_{i} = \sum_{q} \text{OPLPAMTQSETOT}_{i,\,q}$$

$$\text{LCAPCSAMTTOT}_{i} = \sum_{q} \text{LCAPCSAMT}_{i,\,q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LALCAPAMT $_{q,\ i}$	$	*Load Allocated LCAP Effective Period Uplift Charge*—The amount owed from the QSE *q,* based on LRS, for the 15-minute Settlement Interval *i*.
OPLPAMTQSETOT $_{i,\ q}$	$	*Total Operating Losses Payment Amount per QSE* – The total operating losses payment to the QSE *q*, for all Resources, for the 15-minute Settlement Interval *i* within the Operating Day.
OPLPAMTTOT $_{i}$	$	*Total Operating Losses Payment Amount* –The sum of operating losses payments to all QSEs, for the 15-minute Settlement Interval *i*.
LCAPCSAMTTOT $_{i}$	$	*LCAP Capacity-Short Amount Total*—The total of all charges to all QSEs *q*, due to capacity shortfall for an LCAP Effective Period, for the 15-minute Settlement Interval *i*.
LCAPCSAMT $_{i,\ q}$	$	*LCAP Capacity-Short Amount*—The charge to QSE *q*, due to capacity shortfall for an LCAP Effective Period, for the 15-minute Settlement Interval *i*.
LRS $_{q,\ i}$	none	*Load Ratio Share*—The ratio of AML to the total ERCOT AML for the 15-minute Settlement Interval. See Section 6.6.2, Load Ratio Share, item (2).
i	none	A 15-minute Settlement Interval.
q	none	A QSE.

6.8.4 Miscellaneous Invoice for Payments and Charges for an LCAP Effective Period

(1) ERCOT shall issue one-time miscellaneous Invoices using the most recent available Settlement data at the time the Invoices were issued.

(2) ERCOT shall issue miscellaneous Invoices to QSEs for payment of operating losses during an LCAP Effective Period, as described in Section 6.8.2, Recovery of Operating Losses During an LCAP Effective Period.

(3) ERCOT shall issue miscellaneous Invoices and allocate costs to the impacted QSEs as described in Section 6.8.3, Charges for Operating Losses During an LCAP Effective Period.

(4) ERCOT shall issue a Market Notice in conjunction with the issuance of miscellaneous Invoices for payments or charges for an LCAP Effective Period.

ERCOT Nodal Protocols

Section 7: Congestion Revenue Rights

August 1, 2021

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7 CONGESTION REVENUE RIGHTS

7.1 Function of Congestion Revenue Rights

(1) A Congestion Revenue Right (CRR) is a financial instrument that entitles the CRR Owner to be charged or to receive compensation for congestion rents that arise when the ERCOT Transmission Grid is congested in the Day-Ahead Market (DAM) or in Real-Time. CRRs do not represent a right to receive, or obligation to deliver, physical energy. Most CRRs are tradable in the CRR Auction, in the DAM, or bilaterally, as described in more detail in this Section.

(2) CRRs may be acquired as follows:

(a) CRR Auction – ERCOT shall conduct periodic auctions to allow eligible CRR Account Holders to acquire CRRs. The auction also allows CRR Owners an opportunity to sell CRRs that they hold.

(b) PCRR Allocations – ERCOT shall allocate CRRs (known as Pre-Assigned Congestion Revenue Rights (PCRRs)) to eligible Municipally Owned Utilities (MOUs) and Electric Cooperatives (ECs) under Section 7.4, Preassigned Congestion Revenue Rights Overview.

(c) Bilateral Market – CRR Account Holders may trade Point-to-Point (PTP) Options and PTP Obligations bilaterally. PTP Options with Refund and PTP Obligations with Refund are not bilaterally tradable. Bilateral trading may be done privately or through ERCOT. ERCOT shall facilitate trading on the Market Information System (MIS) Certified Area of existing CRRs between CRR Account Holders, subject to credit requirements. ERCOT shall settle CRRs with the CRR Account Holder shown on ERCOT records.

(d) DAM – Qualified Scheduling Entities (QSEs) may bid for PTP Obligations in the DAM.

(3) Each CRR is one of these types:

(a) PTP Option, some of which may be PCRRs;

(b) PTP Obligation, some of which may be PCRRs;

(c) PTP Option with Refund, all of which are PCRRs;

(d) PTP Obligation with Refund, all of which are PCRRs; and

(e) Flowgate Right (FGR).

7.2 Characteristics of Congestion Revenue Rights

(1) Each CRR has the following characteristics:

(a) Quantities are measured in MWs with granularity of tenths of MWs (0.1 MW);

(b) A duration of one hour;

(c) An ability to be fully tradable financial instruments except in specified time-of-use blocks for a PTP Option with Refund and a PTP Obligation with Refund; and

(d) A designated source (injection point) that is a Settlement Point and a designated sink (withdrawal point) that is a different Settlement Point, except for a Flowgate Right (FGR), which has a designated directional network element, or a bundle of directional network elements, instead.

7.2.1 CRR Naming Convention

(1) The appropriate TAC subcommittee shall establish a task force that is open to Market Participants, comprised of technical experts, to develop a naming convention for CRRs consistent with the requirements of the Protocols. The naming convention must be approved by TAC before implementation.

7.3 Types of Congestion Revenue Rights to Be Auctioned

(1) ERCOT shall auction the following types of Congestion Revenue Rights (CRRs):

(a) Point-to-Point (PTP) Options;

(b) PTP Obligations; and

(c) Flowgate Rights (FGRs) that are defined in Section 7.3.1, Flowgates.

(2) PTP Options are evaluated hourly in each CRR Auction as the positive power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points in the quantity represented by the CRR bid or offer (MW), excluding all negative flows on all directional network elements.

(3) PTP Obligations are evaluated hourly in each CRR Auction as the positive and negative power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points of the quantity represented by the CRR bid or offer (MW).

(4) PTP Options can only result in payments from ERCOT to the CRR Owner of record. A PTP Obligation may result in either a payment or a charge to the CRR Owner of record.

(5) CRRs must be auctioned in the following Time Of Use (TOU) blocks (having the same MW amount for each hour within the block):

(a) 5x16 blocks for hours ending 0700-2200, Monday through Friday (excluding North American Electric Reliability Corporation (NERC) holidays), in one-month strips;

(b) 2x16 blocks for hours ending 0700-2200, Saturday and Sunday, and NERC holidays in one-month strips; and

(c) 7x8 blocks for hours ending 0100-0600 and hours ending 2300-2400 Sunday through Saturday, in one-month strips.

(6) CRR Auction bids and Pre-Assigned Congestion Revenue Right (PCRR) nominations must specify a TOU block.

(7) For the CRR Monthly Auction only, a single block bid may be submitted for all hours in a calendar month, which represents a linked-offer for all three TOU blocks described above in paragraph (5).

7.3.1 Flowgates

7.3.1.1 Process for Defining Flowgates

(1) Flowgates where ERCOT offers FGRs may only be created by an amendment to Section 7.3.1.2, Defined Flowgates. ERCOT shall post the list of all flowgates available for FGRs on the ERCOT website. If there is any change in the designation of flowgates, ERCOT shall provide notice to all Market Participants as soon as practicable.

7.3.1.2 Defined Flowgates

(1) There are currently no defined flowgates.

7.4 Pre-Assigned Congestion Revenue Rights Overview

(1) ERCOT shall allocate a portion of available Congestion Revenue Rights (CRRs) as Pre-Assigned Congestion Revenue Rights (PCRRs) to Non-Opt-In Entities (NOIEs) that either have established ownership prior to September 1, 1999 in a specific Generation Resource or have a long-term (greater than five years) contractual commitment for annual capacity and energy that was entered into prior to September 1, 1999 from specific Generation Resources. For purposes of this Section 7.4, such Generation Resources shall be referred to as "pre-September 1, 1999 Generation Resources." An existing Generation Resource that interconnected to the ERCOT Transmission Grid on or after June 1, 2021, pursuant to paragraph (3) of Section 1.6.5, Interconnection of New or Existing

Generation, cannot qualify as a pre-September 1, 1999 Generation Resource for PCRR purposes.

(2) NOIEs are the only Entities eligible for an allocation of PCRRs. NOIEs may designate an agent to manage their PCRRs, provided that ERCOT's relationship is with the NOIE and that an agent shall be subject to all PCRR rules applicable to the NOIE. ERCOT will rely exclusively on documentation provided or confirmed by the NOIE to determine the continued eligibility for allocation of PCRRs.

(3) ERCOT shall publish a list of NOIEs who are eligible for allocation of PCRRs on the ERCOT website. The list shall include each NOIE's ownership and/or contractual amount of capacity related to pre-September 1, 1999 Generation Resources. The list shall further include the eligible PCRR amounts capped at the net max sustainable rating (MW) of pre-September 1, 1999 Generation Resources as established by 2010 registration data. ERCOT shall update the list as necessary to reflect current NOIE eligibility for allocation of PCRRs.

7.4.1 PCRR Allocation Eligibility

7.4.1.1 PCRR Criteria for NOIE Allocation Eligibility

(1) PCRRs shall be limited to pre-September 1, 1999 Generation Resources utilized by a NOIE to serve the Load in its service territory. The following criteria shall apply for NOIE eligibility for allocation of PCRRs:

(a) A Generation Resource owned by the NOIE nominating the PCRR(s) that meets the following:

(i) The NOIE owned the Generation Resource prior to September 1, 1999 and has maintained uninterrupted ownership since September 1, 1999;

(ii) The Generation Resource has remained in service on an uninterrupted basis except for Maintenance Outages, Forced Outages, Opportunity Outages or Planned Outages (including a Mothballed Generation Resource that operates under a Seasonal Operation Period) subsequent to September 1, 1999; and

(iii) The NOIE utilizes the Generation Resource to meet its electric service obligations within its service territory in an amount at least equal to the nominated PCRR amount.

(b) A Generation Resource that is the subject of a long-term contract between the NOIE nominating the PCRR(s) and another Entity that owns or controls the Generation Resource, provided that the long-term contract meets the following criteria:

(i) The contract was entered into prior to September 1, 1999 and has remained in effect on an uninterrupted basis since September 1, 1999;

(ii) The contract term is greater than five years. Contracts with automatic renewal provisions (evergreen clauses), the operation of which extends beyond the term of the contract to more than the cumulative five years, shall meet this requirement, provided that the automatic renewal provision was in place prior to September 1, 1999;

(iii) The NOIE is entitled to capacity from specific Generation Resource(s) pursuant to the long-term contract; long-term contracts that are not backed by specific Generation Resources are not eligible for PCRRs;

(iv) The Generation Resource(s) that is/are the subject of the long-term contract has/have remained in service on an uninterrupted basis except for Maintenance Outages, Forced Outages, Opportunity Outages or Planned Outages (including a Mothballed Generation Resource that operates under a Seasonal Operation Period) since September 1, 1999; and

(v) The Generation Resource(s) that is/are the subject of the long-term contract is/are utilized by the NOIE to meet its electric service obligations within its service territory in an amount at least equal to the nominated PCRR amount.

(c) A federally-owned hydroelectric Generation Resource that is the subject of a series of sequential long-term contracts between the NOIE nominating the PCRR(s) and the federal government based upon a long-term (greater than five years) allocation from the federal government for annual capacity and energy produced at such federally-owned hydroelectric Generation Resource, and that allocation was in place prior to September 1, 1999.

(d) Multiple Generation Resources that are the subject of portfolio supply contracts that meet the requirements of paragraphs (1)(b)(i)-(ii) and (1)(b)(iv)-(v) above and are between a NOIE nominating the PCRR(s) and another non-NOIE. For the purposes of this Section 7.4.1.1, portfolio supply contract shall mean an agreement under which multiple NOIEs receive wholesale capacity from another non-NOIE pursuant to a portfolio of specific Generation Resources. Each NOIE who is eligible for PCRRs and is a party to a portfolio supply contract shall be allocated PCRRs based on its 2003 4-Coincident Peak (4-CP) ratio share of each Generation Resource in the portfolio. The 2003 4-CP ratio share shall be calculated as the 4-CP of each NOIE divided by the total 4-CP of all NOIEs who were supplied by that portfolio of Generation Resources in 2003. Each NOIE's capacity entitlement shall be its 2003 4-CP ratio share multiplied by the net max sustainable rating from the 2010 registration data for each PCRR eligible Generation Resource in the portfolio.

(e) The Direct Current Tie (DC Tie) is considered a PCRR-eligible Generation Resource for contracts of Tex-La Electric Cooperative of Texas, Inc. with supply resources located outside the ERCOT Region that meet the requirements of paragraphs (b)(i)-(ii) and (iv)-(v) above.

(f) A Generation Resource that was the subject of a pre-September 1, 1999 long-term contract between the NOIE nominating the PCRR(s) and another Entity that owned or controlled the Generation Resource prior to September 1, 1999, and that has been acquired by the NOIE after September 1, 1999, shall be deemed for all purposes as a NOIE-owned pre-September 1, 1999 Generation Resource for purposes of paragraph (1) of Section 7.4.1.3.1, PCRR Disqualifying Events, provided that an option for the NOIE to acquire the Generation Resource was in place in the long-term contract prior to September 1, 1999.

7.4.1.2 NOIE Allocation Eligibility for PCRRs Impacted By Long-Term Outages of Generation Resources and Mothballed Generation Resources

(1) A NOIE maintains allocation eligibility for PCRRs associated with a pre-September 1, 1999 Generation Resource that may be out of service for greater than 12 consecutive months if the Generation Resource is out of service pursuant to a Forced Outage and the time necessary to address the relevant Outage extends beyond 12 months, provided that the NOIE must demonstrate to ERCOT's satisfaction that the Outage continues to be necessary and does not require the Resource Entity to cease or suspend operation of the Generation Resource pursuant to Section 3.14.1.1, Notification of Suspension of Operations.

(a) For a PCRR Nomination Year in which a PCRR-eligible Generation Resource is expected to return to service after a long-term Forced Outage (greater than 12 consecutive months), the NOIE is only eligible to receive PCRRs for the months in which the Generation Resource is expected to be in service for the entirety of the month.

(b) If the NOIE nominated and was awarded PCRRs during the annual PCRR allocation process for future months based on an anticipated return to service of a PCRR-eligible Generation Resource from a long-term Forced Outage (greater than 12 consecutive months), the NOIE shall notify ERCOT in writing of the intentions of the Resource Entity to return the Generation Resource to service no less than 60 days prior to the first day of the month in which the Generation Resource is scheduled to return to service. This notice requirement to retain allocated PCRRs is separate and distinct from the return to service requirement in Section 3.14.1.9, Generation Resource Status Updates. If the Generation Resource will not be returned to service for the entirety of a month for which PCRRs were allocated, the associated CRRs will be voided for each impacted month and ERCOT will follow the appropriate option described in Section 7.4.1.3.2, Effect of PCRR Disqualification, in order to maximize the available transmission capacity for future monthly CRR Auctions. To determine if the

NOIE will retain any allocated PCRRs for future months, the NOIE shall provide to ERCOT a new expected return to service date and must follow the notice requirement and timeline in this paragraph above.

(2) A NOIE maintains allocation eligibility for PCRRs associated with a pre-September 1, 1999 Generation Resource if the Generation Resource becomes a Mothballed Generation Resource pursuant to Section 3.14.1.1, Notification of Suspension of Operations, regardless of whether ERCOT determines that the Generation Resource is necessary for Reliability Must-Run (RMR) Service.

(a) However, because the Generation Resource will not provide any capacity or energy to serve the NOIE's Load in its service territory for the period in which it is designated as a Mothballed Generation Resource, a NOIE does not have an exclusive right to retain any allocated PCRRs during this period. For any retained PCRRs, the NOIE shall follow the process detailed in Section 7.4.1.3.2, Effect of PCRR Disqualification.

(b) For a PCRR Nomination Year in which a PCRR-eligible Mothballed Generation Resource is expected to return to service (including a Mothballed Generation Resource that operates under a Seasonal Operation Period), the Generation Resource is only eligible for PCRRs for the months it is expected to be in service for the entirety of the month.

(c) If the NOIE nominated and was awarded PCRRs during the annual PCRR allocation process for future months based on an anticipated return to service of a PCRR-eligible Mothballed Generation Resource, the NOIE shall notify ERCOT in writing of the intentions of the Resource Entity to return the Mothballed Generation Resource to service no less than 60 days prior to the first day of the month in which the Generation Resource is scheduled to return to service. This notice requirement to retain allocated PCRRs is separate and distinct from the return to service requirement in Section 3.14.1.9. If the Mothballed Generation Resource will not be returned to service for the entirety of a month for which PCRRs were allocated, the associated CRRs will be voided for each impacted month and ERCOT will follow the appropriate option described in Section 7.4.1.3.2 in order to maximize the available transmission capacity for future monthly CRR Auctions. To determine if the NOIE will retain any allocated PCRRs for future months, the NOIE shall provide to ERCOT a new expected return to service date and must follow the notice requirement and timeline in this paragraph.

7.4.1.3 PCRR Disqualification

7.4.1.3.1 PCRR Disqualifying Events

(1) A NOIE that owns a pre-September 1, 1999 Generation Resource shall no longer be eligible for allocation of PCRRs associated with that Generation Resource under the following conditions:

(a) The Generation Resource is designated as decommissioned and retired pursuant to Section 3.14.1.1, Notification of Suspension of Operations, regardless of whether ERCOT determines that the Generation Resource is necessary for RMR Service.

(b) The Generation Resource is sold by the NOIE to another Entity, regardless of whether the NOIE later enters into a long-term supply contract with that Entity to serve the NOIE's Load in its service territory. The selling of a Generation Resource shall include the transfer of ownership of the Generation Resource and/or the sale of the energy and/or capacity of the Generation Resource pursuant to a contractual agreement. However, a transfer of the Generation Resource to an Affiliate of the NOIE or to a generation and transmission Electric Cooperative (EC) for the benefit of the NOIE shall not serve as a disqualifying event as long as all other PCRR eligibility requirements remain in place.

(2) A NOIE that has a long-term contract with a pre-September 1, 1999 Generation Resource under paragraph (1)(b) of Section 7.4.1.1, PCRR Criteria for NOIE Allocation Eligibility, shall no longer be eligible for allocation of PCRRs associated with that Generation Resource upon termination of the long-term contract. For purposes of this Section 7.4.1.3.1, termination of the relevant long-term contract shall include:

(a) The Generation Resource is designated as decommissioned and retired pursuant to Section 3.14.1.1, regardless of whether ERCOT determines that the Generation Resource is necessary for RMR Service.

(b) Any change in control of the capacity under the contract, including, but not limited to, assignment of the contract to another Entity. The foregoing notwithstanding, a NOIE shall still be eligible to receive PCRRs if the capacity under the contract is transferred to another Entity or a generation and transmission EC for the benefit of the NOIE, the Entity or the generation and transmission EC continues to supply the NOIE under the same terms and conditions of the long-term contract, and the contract continues to meet all other relevant PCRR eligibility requirements.

(c) Any change in the designation of Generation Resources backing a long-term contract after September 1, 1999, shall disqualify the long-term contract.

(d) If the termination of a long-term contract applies to less than 100% of the capacity entitlement, the remaining capacity entitlement shall continue to qualify for PCRRs for the MW amount under the portion of the long-term contract that is not terminated, provided that the long-term contract otherwise continues to meet all other PCRR eligibility requirements.

(3) A NOIE that has a long-term portfolio supply contract under paragraph (1)(d) of Section 7.4.1.1 shall no longer be eligible for allocation of PCRRs associated with these pre-September 1, 1999 Generation Resources upon termination of the portfolio supply contract. For the purposes of this subsection, termination shall have the same meaning as defined in paragraph (2) above. Following termination of a portfolio supply contract(s) for a NOIE or group of NOIEs, the capacity entitlements remaining under the existing portfolio supply contract(s) shall continue to reflect the 2003 4-CP ratio share values, as described in paragraph (1)(d) of Section 7.4.1.1.

(4) A NOIE that has a long-term contract across the DC Tie with supply resources located outside the ERCOT Region pursuant to paragraph (1)(e) of Section 7.4.1.1 shall no longer be eligible for allocation of PCRRs upon termination of the relevant external supply contract(s). For purposes of this Section 7.4.1.3.1, termination shall have the same meaning as defined in paragraph (2) above. If the termination of the external supply contract(s) applies to less than 100% of the capacity entitlement, the remaining capacity entitlement shall continue to qualify for PCRRs for the MW amount under the portion of the external supply contract(s) that is not terminated, provided that the external supply contract(s) continues to meet all other PCRR eligibility requirements.

(5) A NOIE that has long-term contracts pursuant to paragraph (1)(b) of Section 7.4.1.1, portfolio supply contracts pursuant to paragraph (1)(d) of Section 7.4.1.1 or long-term contracts pursuant to paragraph (1)(e) of Section 7.4.1.1 that did not contain automatic renewal provisions (evergreen clauses) in the original contracts and were subsequently revised to extend the term of the relevant contracts after September 1, 1999, shall not be eligible for allocation of PCRRs upon expiration of the original terms of the contracts (*i.e.* the date the contract would have expired but for extension of the term pursuant to post-September 1, 1999 contract modifications). Disqualification pursuant to this Section 7.4.1.3.1 applies to any type of term extension modifications after September 1, 1999, whether they are automatic renewal provisions (evergreen clauses) or other renewal and extension provisions.

(6) A NOIE shall no longer be eligible for allocation of PCRRs after it opts into competition, with the exception of South Texas Electric Cooperative Inc. (STEC). STEC may be eligible for allocation of PCRRs for up to three years after the date it enters into competition.

7.4.1.3.2 Effect of PCRR Disqualification

(1) Once a disqualifying event occurs under Section 7.4.1.3.1, PCRR Disqualifying Events, the PCRRs associated with the pre-September 1, 1999 Generation Resource shall be voided by ERCOT from the date of the disqualifying event. Further, the NOIE will no longer be eligible for allocation of future PCRRs associated with the pre-September 1, 1999 Generation Resource.

(2) However, if a disqualifying event occurs during the effective term of the PCRRs, the NOIE who was allocated the PCRRs shall select one of the options below to address the remaining allocated PCRRs.

(a) If the NOIE maintains PCRR-related CRRs in its CRR Account, then the CRRs associated with the PCRR allocation shall either:

(i) Be voided by ERCOT at the time of the disqualifying event and ERCOT shall refund the NOIE the discounted purchase price of the CRR as soon as practicable; or

(ii) Be retained by the NOIE and the NOIE pays ERCOT the price differential between the discounted CRR price and the full CRR Auction price in which the CRR was acquired.

(b) If the NOIE no longer maintains PCRR-related CRRs (sale, transfer, etc.), then the NOIE pays ERCOT the price differential between the discounted CRR price and the full CRR Auction price in which the CRR was acquired.

(c) If the NOIE obtained PCRR-related CRRs through the Refund option (allocated at no charge), then ERCOT will void the CRRs at the time of the disqualifying event and no financial exchange is necessary.

7.4.2 PCRR Allocation and Nomination Terms and Conditions

7.4.2.1 PCRR Allocation and Nomination Amounts

(1) PCRR allocations shall be limited to the Seasonal net max sustainable rating (MW) of eligible pre-September 1, 1999 Generation Resources, but shall in no event exceed the net max sustainable rating (MW) of these pre-September 1, 1999 Generation Resources as established by 2010 registration data. If a Generation Resource is repowered by the addition of new equipment, the PCRR MW amount is limited to the original specific turbine/generator set(s) from the pre-September 1, 1999 Generation Resource. New or upgraded components that increase the capacity of pre-September 1, 1999 Generation Resources are not eligible for increased PCRR MW amounts.

(2) PCRR nominations shall be based on forecasted peak Demand, subject to the relevant PCRR allocation MW capacity limit of the specific Generation Resources.

(3) The PCRR allocation amounts for individual NOIEs relative to multiple Generation Resources under a portfolio supply contract shall be based on the following:

(a) If the portfolio supply contract specifically describes the NOIE capacity entitlement from each specific Generation Resource, the PCRR allocation amount from each Generation Resource shall be based on the contractual rights.

(b) If the portfolio supply contract does not specifically describe the NOIE capacity entitlement from each specific Generation Resource, the PCRR allocation amount shall be based on the NOIE's 2003 4-Coincident Peak (4-CP) ratio share of each Generation Resource in the portfolio. The 2003 4-CP ratio share shall be calculated as the 4-CP of each NOIE divided by the total 4-CP of all NOIEs who were supplied by that portfolio of Generation Resources in 2003. Each NOIE's capacity entitlement shall be its 2003 4-CP ratio share multiplied by the net max sustainable rating from the 2010 registration data for each PCRR eligible Generation Resource in the portfolio.

(4) If a NOIE serves Load in more than one Load Zone, it shall nominate PCRRs to each Load Zone in an amount equal to the explicit contractual rights to each Load Zone, if any, or in proportion to the peak Load served in each relevant Load Zone, based on the aggregated monthly Load data from the corresponding prior 12 months.

7.4.2.2 PCRR Allocations and Nominations

(1) ERCOT shall allocate CRRs under the following terms and conditions:

(a) ERCOT shall conduct studies to evaluate whether the nominated PCRRs comply with feasibility constraints using the simultaneous feasibility test described in Section 7.5.5.4, Simultaneous Feasibility Test. A PCRR nomination is a request for one-month strips of a NOIE-specified CRR type for amounts and blocks specified by the NOIE for each month of the PCRR Nomination Year as described in paragraph (c) below. The Simultaneous Feasibility Test (SFT) evaluation to determine the feasible PCRR allocation amount for each month being evaluated uses 100% of that month's expected network topology, which may result in different amounts allocated in different months. If the SFT evaluation indicates that the nominated PCRR amounts are not feasible, then ERCOT shall proportionately reduce the requested PCRRs by their Impact Ratio on violated constraints. The "Impact Ratio" is the amount of a particular PCRR's impact divided by the total impact of all PCRRs in the same direction on a violated constraint. The price that a NOIE must pay for an allocated PCRR is based on the corresponding CRR clearing price in the CRR First Offering. The invoicing and payment for a PCRR allocated according to the process in this paragraph follows the same process and timeline as the invoicing and payment of CRR bids cleared in the CRR First Offering.

(b) ERCOT shall allocate all PCRRs in quantities truncated to the nearest tenth MW (0.1 MW).

(c) Each eligible NOIE may nominate and ERCOT shall allocate to that NOIE as so nominated, subject to the limitation of paragraph (a) above, PCRRs up to 100% of the amount allowed pursuant to Section 7.4.2.1, PCRR Allocation and Nomination Amounts, for each eligible Resource, except as noted below in paragraph (d). Prior to the first CRR Long-Term Auction Sequence held in any given calendar year, the NOIE must nominate PCRRs for each month of the PCRR Nomination Year. Nominations must be received at ERCOT no later than 30 Business Days prior to the commencement of the CRR Long-Term Auction Sequence. ERCOT shall allocate PCRRs to the NOIE no later than 25 Business Days prior to the CRR Long-Term Auction Sequence. There shall not be any PCRR nomination process leading up to the second CRR Long-Term Auction Sequence (if any) in a calendar year.

(d) Prior to each CRR Monthly Auction, if there existed any PCRR nominations for the month being auctioned that ERCOT determined were not feasible at the time of the CRR Long-Term Auction Sequence in which they were originally considered, resulting in proportionally reduced PCRR allocations, then ERCOT shall re-evaluate the full nomination and allocate additional PCRRs, if feasible, up to the original nomination amount. The price that a NOIE must pay for a PCRR allocated by the process in this paragraph is based on the corresponding CRR clearing price in the CRR Monthly Auction according to the pricing methodology in item (h) below, and the invoicing and payment for such a PCRR follows the same process and timeline as the invoicing and payment of CRR bids cleared in the CRR Monthly Auction.

(e) A NOIE must designate whether to accept the refund option or the capacity option for its eligible non-solid fuel and non-combined-cycle Resources before the allocation of PCRRs. The designated option (refund or capacity) will be the same for every month of the allocation year for that Resource. A NOIE cannot designate a combination of both options for the same Resource in a given allocation year. These options are described in items (i) and (ii) below. NOIEs, or a group of NOIEs linked by common pre-1999 power supply arrangements, which had a 2003 NOIE peak Load in excess of 2,300 MW must use the capacity option (ii) for their eligible non-solid-fuel and non-combined-cycle Resources. NOIEs that receive PCRRs representing gas steam Resources, hydro, wind, simple cycle or other similar Resources across high voltage DC Ties must use the capacity option (ii) for those eligible non-solid-fuel and non-combined-cycle Resources:

(i) Refund option – The eligible NOIE may nominate up to 100% of the lesser of the net unit capacity or contractual amount for those Resource amounts allowed pursuant to Section 7.4.2.1. The eligible NOIE shall refund to ERCOT any congestion revenues received above those congestion revenues flowing to the NOIE for its Output Schedule of the Resource at the PCRR source. PCRR settlement will reflect the MW value of the Output Schedule of the Resource at the PCRR source, regardless of what MW value of actual output occurred during that interval if that change in output is in response to Dispatch Instructions. The refund for any Settlement Interval is equal to the difference between the PCRR MW amount and the time-weighted average of the Output Schedules of the Resource at the PCRR source multiplied by the value of that PCRR. PCRRs allocated under the refund option are not transferable and may only be used by the NOIE to which they are allocated.

(ii) Capacity option – The eligible NOIE may nominate up to 100% of the lesser of the net unit capacity or contractual amount for those Resource amounts allowed pursuant to Section 7.4.2.1 at a capacity factor no greater than 40% over each calendar year. ERCOT shall allocate PCRRs in accordance with the NOIE nominations subject to the SFT.

(A) During the nomination process, the NOIE must nominate the months (designating CRR amounts as defined by the criteria specified in item (5) of Section 7.3, Types of Congestion Revenue Rights to Be Auctioned) for which it will use its PCRRs (i.e., the NOIE may shape the PCRRs representing up to 100% of the capacity for each Resource at a capacity factor no greater than 40% over each calendar year).

(B) If a Resource eligible for PCRRs is shut down due to a Force Majeure Event, then, to the extent feasible, the NOIE may reallocate its PCRRs across its PCRR-eligible facilities before the CRR Monthly Auction. This change is effective no later than the date of the CRR Monthly Auction, and the redesignation may be requested for each CRR Monthly Auction during the Force Majeure Event. Any price difference in the reconfigured rights must be paid by (or paid to) the NOIE.

(f) The CRR type, either Point-to-Point (PTP) Option, PTP Obligation, or a combination, must be specified by the eligible NOIE before the PCRR allocation and is binding for purchase. Once the allocation process is complete, the eligible NOIE may not change the CRR type.

(g) After the allocation process, and the subsequent applicable CRR Auction, PCRRs other than those described in item (iii) below must be priced as a percentage of the applicable CRR Auction clearing price for the applicable CRR, as follows:

(i) PTP Option PCRRs:

(A) **Nuclear, coal, lignite or combined-cycle Resources:** 10% of the applicable CRR Auction clearing prices;

(B) **Gas steam Resources:** 15% of the applicable CRR Auction clearing prices; or

(C) **Hydro, wind, simple cycle, or other Resources not included in (A) or (B):** 20% of the applicable CRR Auction clearing prices.

(ii) PTP Obligation PCRRs:

(A) **Nuclear, coal, lignite or combined-cycle Resources**: 5% of the applicable CRR Auction clearing price if it is positive; 100% of the applicable CRR Auction clearing price if it is negative;

(B) **Gas steam Resources:** 7.5% of the applicable CRR Auction clearing price if such price is positive; 100% of the applicable CRR Auction clearing price if it is negative; or

(C) **Hydro, wind, simple cycle, or other Resources not included in (A) or (B):** 10% of the applicable CRR Auction clearing prices if it is positive; 100% of the applicable CRR Auction clearing prices if it is negative.

(iii) For a NOIE that has chosen the refund option, the allocated number of PCRRs for Resources other than solid-fuel and combined-cycle Resources are provided at no charge.

(h) PCRRs shall not be able to be bilaterally traded through ERCOT systems prior to the completion of the CRR Auction used to determine their value.

7.5 CRR Auctions

7.5.1 Nature and Timing

(1) The Congestion Revenue Right (CRR) Auction auctions the available network capacity of the ERCOT transmission system not allocated as described in Section 7.4, Preassigned Congestion Revenue Rights Overview, or sold in a previous auction. The CRR Auction also allows CRR Owners an opportunity to offer for sale CRRs that they hold. Each CRR Auction allows for the purchase of CRR products as described in paragraph (5) of Section 7.3, Types of Congestion Revenue Rights to Be Auctioned, in strips of one or more consecutive months and allows for the reconfiguration of all CRR blocks that were previously awarded for the months covered by that CRR Auction.

(2) The CRR Network Model must be based on, but is not the same as, the Network Operations Model. For the purposes of CRR Network Model construction for a CRR Long-Term Auction Sequence, ERCOT may, at its sole discretion, utilize the same or similar CRR Network Model inputs for multiple consecutive months. The CRR Network Model must, to the extent practicable, include the same topology, contingencies, and operating procedures as used in the Network Operations Model as reasonably expected to be in place for each month. The expected network topology used in the CRR Network Model for any month or set of months must include all Outages from the Outage Scheduler and identified by ERCOT as expected to have a significant impact upon transfer capability during that time. These Outages included in the CRR Network Model shall be posted on the Market Information System (MIS) Secure Area consistent with model posting requirements by ERCOT with accompanying cause and duration information, as indicated in the Outage Scheduler. Transmission system upgrades and

changes must be accounted for in the CRR Network Model for CRR Auctions held after the month in which the element is placed into service.

(a) ERCOT shall use Dynamic Ratings in the CRR Network Model as required under Section 3.10.8, Dynamic Ratings.

(b) The CRR Network Model must use the peak Load conditions of the month or set of months being modeled.

(c) ERCOT's criteria for determining if an Outage should be in the CRR Network Model shall be in accordance with these Protocols and described in the Operating Guides.

(3) ERCOT shall model bids and offers into the CRR Auction as flows based on the MW offer and defined source and sink. When the Simultaneous Feasibility Test (SFT) is run, the model must weight the power flow buses and Hub Buses included in a Hub or Load Zone appropriately to determine the system impacts of the CRRs.

(a) To distribute injections and withdrawals to buses within a Hub, ERCOT shall use distribution factors specified in Section 3.5.2, Hub Definitions.

(b) To distribute injections and withdrawals to power flow buses in Load Zones, ERCOT shall use the Load-weighted distribution factors for On-Peak Hours in each Load Zone. For a CRR Monthly Auction, ERCOT shall derive CRR Auction Load distribution factors with the set of Load distribution factors constructed in accordance with the ERCOT Load distribution factor methodology specified in paragraph (5) of Section 4.5.1, DAM Clearing Process, for use in the Day-Ahead Market (DAM). For a CRR Long-Term Auction Sequence, ERCOT shall derive CRR Auction Load distribution factors from the corresponding planning model or with the set of Load distribution factors constructed in accordance with the ERCOT Load distribution factor methodology specified in paragraph (5) of Section 4.5.1, for use in the DAM. ERCOT shall notify the market as to which method was used for each CRR Network Model in a CRR Long-Term Auction Sequence in the corresponding auction notice. ERCOT shall post the CRR Auction Load distribution factors as part of the CRR Network Model pre-auction posting. Private Use Network net Load will be redacted from this posting.

[NPRR1004: Replace paragraph (b) above with the following upon system implementation:]

(b) To distribute injections and withdrawals to power flow buses in Load Zones, ERCOT shall use the Load-weighted distribution factors for On-Peak Hours in each Load Zone. For CRR Auctions and allocations, ERCOT shall derive Load distribution factors with the set of Load distribution factors constructed in accordance with the ERCOT Load distribution factor methodology specified in paragraph (c) of Section 3.12, Load Forecasting. ERCOT shall post the CRR Auction Load distribution factors as part of the CRR Network Model pre-auction posting. Private Use Network net Load will be redacted from this posting.

(4) ERCOT shall conduct CRR Auctions as follows:

(a) The CRR Monthly Auction, held once per calendar month, shall include the sale of one-month terms of Point-to-Point (PTP) Options and PTP Obligations for the month immediately following the month during which the CRR bid submission window closes.

(b) Twice per year, a CRR Long-Term Auction Sequence shall be held, selling PTP Options and PTP Obligations, subject to the following constraints:

(i) Each CRR Long-Term Auction Sequence shall consist of six successive CRR Auctions, each of which offers for sale CRRs spanning a term of six consecutive calendar months (either January through June, or July through December). In each such CRR Auction, CRRs shall be offered in one-month strips or in strips of up to six consecutive months within the term covered by the auction.

(ii) The CRR Long-Term Auction Sequence shall operate in chronological order, first providing a CRR Auction covering the next six-month (January through June, or July through December) period that has not yet commenced, and then five successive CRR Auctions for the five six-month periods thereafter.

(c) No later than April 1 of each calendar year, ERCOT shall publish an update to the CRR activity calendar on the ERCOT website, with the following requirements:

(i) The calendar shall include activity dates for all CRR Monthly Auctions, all CRR Auctions that are part of a CRR Long-Term Auction Sequence, and all Pre-Assigned Congestion Revenue Right (PCRR) annual allocations for the remainder of the current calendar year and for the two subsequent calendar years.

(ii) Any posted date on the CRR activity calendar shall only be modified if ERCOT determines that the successful execution of the auction would be jeopardized without such modification. If a delay in completion of a CRR Auction that is part of a CRR Long-Term Auction Sequence results in a condition whereby an overlap of credit posting requirements for consecutive CRR Auctions within that sequence would occur, subsequent CRR Auctions within the sequence shall be delayed by the minimum amount of time required to relieve such overlap. For any changes to the posted auction activity dates, ERCOT will send a Market Notice to provide the new date(s) and to explain the need for the change.

(iii) The CRR activity calendar must be approved by the Wholesale Market Subcommittee (WMS) prior to the annual posting.

(5) For each CRR Auction, the CRR Auction Capacity shall be defined as follows:

(a) For the CRR Monthly Auction, 90%.

(b) For any CRR Auction that is part of a CRR Long-Term Auction Sequence, 70%, 55%, 40%, 30%, 20%, or 10% for the first, second, third, fourth, fifth, and sixth six-month windows sold in the sequence, respectively.

(6) For any month covered by a CRR Auction that is part of a CRR Long-Term Auction Sequence, ERCOT shall offer network capacity equal to:

(a) The expected network topology for that month, scaled down to the CRR Auction Capacity percentage; minus

(b) All outstanding CRRs that were previously allocated for the month, scaled down to the CRR Auction Capacity percentage; minus

(c) All outstanding CRRs that were previously awarded for the month in any previous CRR Auction.

(7) For the CRR Monthly Auction, ERCOT shall offer network capacity equal to the difference between:

(a) The expected transmission network topology in the CRR Network Model of the month for which the CRRs are effective scaled down to the CRR Auction Capacity percentage; and

(b) All outstanding CRRs that were previously awarded or allocated for the month.

7.5.2 CRR Auction Offers and Bids

(1) To submit bids or offers into a CRR Auction, an Entity must become a CRR Account Holder and satisfy financial assurance criteria required to participate, under Section 16.8, Registration and Qualification of Congestion Revenue Rights Account Holders.

(2) In order to enforce a volume limitation on the number of market transactions (bids and offers) submitted into the CRR Auction, ERCOT shall evaluate the maximum number of transactions which are available prior to the auction, and evenly divide the limit across the CRR Account Holders eligible to submit bids or offers according to paragraph (1) above. This limit shall be designated as the preliminary allocated CRR transaction limit. The preliminary allocated CRR transaction limitation for all CRR Account Holders will be communicated as part of the CRR Auction Notice prior to each auction.

(a) Prior to executing the CRR Auction but after the transaction submission window is closed, ERCOT shall determine which of the CRR Account Holders are Participating CRR Account Holders for that CRR Auction. ERCOT shall then calculate a final allocated CRR transaction limit by evenly dividing the number of available transactions across the Participating CRR Account Holders.

(b) The Technical Advisory Committee (TAC) shall establish transaction limits for the CRR Auctions for Participating CRR Account Holders. As part of TAC consideration to establish or change transaction limits, ERCOT shall provide upon TAC request to TAC or a TAC-designated subcommittee the historical number of transactions submitted by each CRR Account Holder and the number of active CRR Account Holders aggregated up to the associated Counter-Party for each requested CRR Auction without identifying the names of the CRR Account Holders or Counter-Parties. Upon TAC approval of a change in transaction limits, ERCOT shall post these values as part of the next regularly scheduled CRR Auction Notice. Only Participating CRR Account Holders are allowed to submit transactions for consideration in the relevant CRR Auction.

(c) If the total number of transactions submitted by all Participating CRR Account Holders into the CRR Auction does not exceed the maximum number of transactions available prior to the auction, then the final allocated CRR transaction limit will not apply and all transactions will be accepted.

(d) Within one hour after the close of each CRR Auction, ERCOT shall notify all CRR Account Holders of the total number of transactions submitted by all Participating CRR Account Holders and whether or not a transaction adjustment period is necessary. ERCOT may determine that a transaction adjustment period is not necessary if the total number of transactions submitted by all Participating CRR Account Holders does not exceed the number of transactions that can be processed by the CRR Auction system.

(e) If ERCOT announces a transaction adjustment period, ERCOT shall notify all CRR Account Holders of the final allocated transaction limit and reject all transactions submitted by each Participating CRR Account Holder whose sum total of transactions submitted to the affected CRR Auction exceeds the final allocated transaction limit. Each Participating CRR Account Holder may then adjust their transactions while respecting the final allocated CRR transaction limitation for the affected CRR Auction within one Business Day. ERCOT will then execute the CRR Auction using the updated set of transactions as revised by Market Participants.

(f) Each Counter-Party is limited to a total of three CRR Account Holders.

(g) ERCOT shall determine a charge for each PTP Option bid awarded in each CRR Auction as described in Section 7.7, Point-to-Point (PTP) Option Award Charge.

[NPRR936: Replace paragraph (2) above with the following upon system implementation:]

(2) In order to enforce a volume limitation on the number of market transactions (bids and offers) submitted into the CRR Auction, ERCOT shall evaluate the maximum number of

transactions which are available prior to the auction, and evenly divide the limit across the Counter-Parties that are associated with CRR Account Holders eligible to submit bids or offers according to paragraph (1) above. This limit shall be designated as the preliminary allocated CRR transaction limit. The preliminary allocated CRR transaction limitation for all Counter-Parties will be communicated as part of the CRR Auction Notice prior to each auction.

(a) Prior to executing the CRR Auction but after the transaction submission window is closed, ERCOT shall determine which of the Counter-Parties are associated with Participating CRR Account Holders for that CRR Auction. ERCOT shall then calculate a final allocated CRR transaction limit by evenly dividing the number of available transactions across the Counter-Parties associated with Participating CRR Account Holders.

(b) The Technical Advisory Committee (TAC) shall establish transaction limits for the CRR Auctions for Counter-Parties associated with Participating CRR Account Holders. As part of TAC consideration to establish or change transaction limits, ERCOT shall provide upon TAC request to TAC or a TAC-designated subcommittee the historical number of transactions submitted by each CRR Account Holder and the number of active CRR Account Holders aggregated up to the associated Counter-Party for each requested CRR Auction without identifying the names of the CRR Account Holders or Counter-Parties. Upon TAC approval of a change in transaction limits, ERCOT shall post these values as part of the next regularly scheduled CRR Auction Notice. Only Participating CRR Account Holders are allowed to submit transactions for consideration in the relevant CRR Auction.

(c) If the total number of transactions submitted by all Participating CRR Account Holders into the CRR Auction does not exceed the maximum number of transactions available prior to the auction, then the final allocated CRR transaction limit will not apply and all transactions will be accepted.

(d) Within one hour after the close of each CRR Auction, ERCOT shall notify all CRR Account Holders of the total number of transactions submitted by all Participating CRR Account Holders and whether or not a transaction adjustment period is necessary. ERCOT may determine that a transaction adjustment period is not necessary if the total number of transactions submitted by all Participating CRR Account Holders does not exceed the number of transactions that can be processed by the CRR Auction system.

(e) If ERCOT announces a transaction adjustment period, ERCOT shall notify all CRR Account Holders of the final allocated transaction limit and reject all transactions submitted by each Participating CRR Account Holder associated with a Counter-Party whose sum total of transactions submitted to the affected CRR Auction exceeds the final allocated transaction limit. Each Participating CRR Account Holder may then adjust their transactions while respecting the final allocated CRR transaction limitation for the affected CRR Auction within one

Business Day. ERCOT will then execute the CRR Auction using the updated set of transactions as revised by Market Participants.

(f) ERCOT shall determine a charge for each PTP Option bid awarded in each CRR Auction as described in Section 7.7, Point-to-Point (PTP) Option Award Charge.

7.5.2.1 CRR Auction Offer Criteria

(1) A CRR Auction Offer indicates a willingness to sell CRRs at the auction clearing price, if it equals or exceeds the Minimum Reservation Price. It must be submitted by a Participating CRR Account Holder and must include the following:

(a) The short name of the Participating CRR Account Holder;

(b) The unique identifier for each CRR being offered, which must include the single type of CRR being offered;

(c) The source Settlement Point and the sink Settlement Point for the block of CRRs being offered;

(d) The month, or strip of consecutive months, for which the block of CRRs is being offered, including time-of-use designation except that a 7x24 offer may not be designated;

(e) The quantity of CRRs in MW, which must be the same for each hour within the block, for which the Minimum Reservation Price is effective; and

(f) A dollars per CRR (i.e. dollars per MW per hour) for the Minimum Reservation Price.

(2) The Participating CRR Account Holder may submit a self-imposed credit limit for the CRR Monthly Auction or for each time-of-use in a CRR Auction that is part of a CRR Long-Term Auction Sequence, if desired.

(3) A Participating CRR Account Holder can only offer to sell one-month or multi-month strips of CRRs for which it is the CRR Owner of record at the time of the offer. Multi-month CRR offers must consist of consecutive months that are within the period of the relevant CRR Auction and can only be submitted as part of a CRR Long-Term Auction Sequence.

(4) A CRR offer for a specified MW quantity of CRRs constitutes an offer to sell a quantity of CRRs equal to or less than the specified quantity. A CRR offer may not specify a minimum quantity of MW that the Participating CRR Account Holder wishes to sell.

7.5.2.2 CRR Auction Offer Validation

(1) A valid CRR Auction Offer is a CRR Auction Offer that ERCOT has determined meets the criteria listed in Section 7.5.2.1, CRR Auction Offer Criteria.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any CRR Account Holder submitting a CRR Auction Offer to view its valid CRR Auction Offers.

(3) As soon as practicable, ERCOT shall notify each CRR Account Holder of any of its CRR Auction Offers that are invalid. The CRR Account Holder may correct and resubmit any invalid CRR Auction Offer, within the appropriate auction timeline.

7.5.2.3 CRR Auction Bid Criteria

(1) A CRR Auction Bid indicates a willingness to buy CRRs at the auction clearing price, if it is equal to or less than the Not-to-Exceed Price. It must be submitted by a Participating CRR Account Holder and must include the following:

(a) The short name of the Participating CRR Account Holder;

(b) The single type of CRR being bid;

(c) The source Settlement Point and the sink Settlement Point for the block of CRRs being bid;

(d) The month or strip of consecutive months for which the block of CRRs is being bid, including time-of-use designation, which may include a 7x24 block in a CRR Monthly Auction but not in a CRR Auction held as part of a CRR Long-Term Auction Sequence;

(e) The quantity of CRRs in MW, which must be the same for each hour within the block, for which the Not-to-Exceed Price is effective; and

(f) A dollars per CRR (i.e. dollars per MW per hour) for the Not-to-Exceed Price.

(2) The Participating CRR Account Holder may submit a self-imposed credit limit for the CRR Monthly Auction or for each time-of-use in a CRR Auction that is part of a CRR Long-Term Auction Sequence, if desired.

(3) A bid to buy a PTP Option cannot specify a non-positive Not-to-Exceed Price less than the Minimum PTP Option Bid Price.

(4) A bid to buy a PTP Obligation can specify a negative Not-to-Exceed Price.

(5) A CRR bid for a specified MW quantity of CRRs constitutes a bid to buy a quantity of CRRs equal to or less than the specified quantity. A CRR bid may not specify a minimum quantity of MW that the Participating CRR Account Holder wishes to buy.

(6) A CRR bid may not contain a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points, nor may CRR bids be submitted by any combination of Participating CRR Account Holders within the same Counter-Party to create the net effect of a single PTP Obligation bid containing a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points.

7.5.2.4 CRR Auction Bid Validation

(1) A valid CRR Auction Bid is a CRR Auction Bid that ERCOT has determined meets the criteria listed in Section 7.5.2.3, CRR Auction Bid Criteria.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any CRR Account Holder submitting a CRR Auction Bid to view its valid CRR Auction Bids.

(3) As soon as practicable, ERCOT shall notify each CRR Account Holder of any of its CRR Auction Bids that are invalid. The CRR Account Holder may correct and resubmit any invalid CRR Auction Bid, if within the appropriate auction timeline.

7.5.3 ERCOT Responsibilities

(1) ERCOT shall:

(a) Manage the qualification and registration of eligible CRR Account Holders;

(b) Post calendar of CRR Auctions;

(c) Initiate, direct, and oversee the CRR Auction;

(d) Post CRR Auction results;

(e) Maintain a record of the CRRs;

(f) Provide a mechanism to record CRR bilateral transactions;

(g) Determine CRR Auction Settlement and distribute auction revenues;

(h) Keep, under the ERCOT data retention policy, all information and tools necessary to reproduce CRR calculations; and

(i) Post CRR Network Model of the effective month of the auction on the MIS Secure Area, before each CRR Auction:

(i) For the CRR Monthly Auction, the model shall be posted no later than ten Business Days before the auction.

(ii) For any CRR Long-Term Auction Sequence, the models shall be posted no later than 20 Business Days before the sequence commences.

(2) ERCOT shall use the CRR Network Model as defined in Section 3.10.3, CRR Network Model.

(3) ERCOT shall develop and maintain a CRR guide to help Market Participants with the CRR program.

(4) Before each auction, ERCOT shall establish a credit limit under Section 16, Registration and Qualification of Market Participants, that is imposed in the CRR Auction.

(5) Five Business Days prior to the credit lock for each CRR Auction, ERCOT shall post on the ERCOT website the credit related path-specific DAM-based adders and the historical CRR Auction clearing prices as applicable in support of the credit adders defined in Section 7.5.5.3, Auction Process, for the existing CRR Inventory.

7.5.3.1 Data Transparency

(1) Following each CRR Auction, ERCOT shall record and make available to each CRR Account Holder on the MIS Certified Area the following information for each CRR awarded in, sold in, or allocated before, the CRR Auction to the specific CRR Account Holder:

(a) Unique identifier of each CRR;

(b) Type of CRR (PTP Option, PTP Obligation, PTP Option with Refund, or PTP Obligation with Refund);

(c) Clearing price and, if applicable, the PCRR pricing factor of each CRR;

(d) The source and sink of each CRR;

(e) The date and time-of-use block for which the CRR is effective; and

(f) Total MW of each PTP pair of CRR, awarded, sold or allocated.

(2) Following each CRR Auction, ERCOT shall post to the ERCOT website the following information for all outstanding or sold CRRs following this auction:

(a) PTP Options and PTP Options with Refund – the source and sink, and total MWs;

(b) PTP Obligations and PTP Obligations with Refund – the source and sink and total MWs;

(c) The identities of the CRR Account Holders that sold, were awarded, or were allocated CRRs in or before the CRR Auction;

(d) The clearing prices for each strip of CRR Auction bids and CRR Auction offers awarded in the CRR Auction;

(e) The identity and post contingency flow of each binding directional element based on the CRR Network Model used in the CRR Auction;

(f) All CRR Auction bids and CRR Auction offers, without identifying the name of the CRR Account Holder that submitted the bid or offer;

(g) The clearing prices for each strip of CRRs bid or offered in the CRR Auction;

(h) The Shadow Prices for each Settlement Point in the CRR Auction; and

(i) The clearing prices for all outstanding CRRs that were previously awarded or allocated for the month(s) in the CRR Auction.

(3) Following a one-time auction of CRRs pursuant to Section 16.11.6.1.4, Repossession of CRRs by ERCOT, or Section 16.11.6.1.5, Declaration of Forfeit of CRRs, ERCOT shall post to the ERCOT website the following information for all CRRs sold in the auction:

(a) PTP Options – the source and sink, total MWs, and date and time-of-use block for which the CRR is effective;

(b) PTP Obligations – the source and sink, total MWs, and date and time-of-use block for which the CRR is effective; and

(c) The identity of the CRR Account Holder that was awarded CRRs in the one-time CRR Auction.

[NPRR1023: Delete paragraph (3) above upon system implementation.]

7.5.3.2 Auction Notices

(1) Not less than 20 days before each CRR Long-Term Auction Sequence and not less than ten days before each CRR Monthly Auction, ERCOT shall post the following to the ERCOT website:

(a) For the CRR Auction, number and type (PTP Options or PTP Obligations) of CRRs previously awarded or allocated for each appropriate month, including the source and sink for each such CRR;

(b) Deadline for CRR Account Holders to satisfy financial requirements to participate in the auction;

(c) Specifications for the equipment and interfaces necessary to participate in the CRR Auction;

(d) Date and time by which CRR Auction bids and CRR Auction offers in the CRR Auction must be submitted;

(e) Bid and offer format;

(f) Minimum PTP Option Bid Price;

(g) The preliminary allocated CRR transaction limit as defined in paragraph (2) of Section 7.5.2, CRR Auction Offers and Bids; and

(h) Any other relevant information of commercial significance to CRR Account Holders, including a list of Electrically Similar Settlement Points.

7.5.4 CRR Account Holder Responsibilities

(1) Participating CRR Account Holders may submit CRR Auction Bids and CRR Auction Offers.

(2) Each CRR Account Holder must maintain adequate credit for its CRR holdings, and CRR Auction participation requirements, as described in Section 16, Registration and Qualification of Market Participants.

7.5.5 Auction Clearing Methodology

7.5.5.1 Creditworthiness

(1) The CRR Auction system prevents a CRR Account Holder from being awarded bids and offers that exceed the lesser of the CRR Account Holder's self-imposed credit limit or the credit limit as prescribed in Section 16.11.4.6.1, Credit Requirements for CRR Auction Participation.

7.5.5.2 Disclosure of CRR Ownership

(1) ERCOT shall post monthly, by the fifth Business Day of the month, on the ERCOT website CRR ownership of record information for each source and sink pair as follows:

(a) The identities of the CRR Account Holders;

(b) Type of CRR held by that account holder; and

(c) Total MWs held by that account holder.

7.5.5.3 Auction Process

(1) The CRR Auction must be a single-round, simultaneous auction for selling the CRRs available for all auction products. ERCOT shall enter into the CRR Auction system a credit limit for each Counter-Party that has at least one CRR Account Holder. A Counter-Party's CRR Auction credit limit is equal to the lesser of the credit limit as determined in Section 16.11.4.6.1, Credit Requirements for CRR Auction Participation, or, if provided, the Counter-Party's self-imposed CRR Auction credit limit for the CRR Monthly Auction or for a time-of-use within a CRR Auction held as part of a CRR Long-Term Auction Sequence.

(2) Prior to the CRR Auction, ERCOT will conduct a two-part pre-auction screening process. First, if the Counter-Party's CRR Auction credit limit is greater than that Counter-Party's credit exposure as defined below using the CRR bid volumes rather than awarded volumes, then the Counter-Party's CRR Auction credit limit will be ignored as the CRR Auction is solved. Second, for each CRR Account Holder of a Counter-Party, if the CRR Account Holder's self-imposed credit limit is greater than that CRR Account Holder's credit exposure as defined below, then the CRR Account Holder's self-imposed credit limit will be ignored as the CRR Auction is solved.

The calculated exposure for the pre-auction screening for each CRR Account Holder is the sum of the credit exposure for PTP Obligation bids, PTP Obligation offers, and PTP Option bids for that CRR Account Holder. The calculated exposure for the pre-auction screening for each Counter-Party is the sum of the credit exposure for PTP Obligation bids, PTP Obligation offers, and PTP Option bids for that Counter-Party. PTP Option offers have zero credit exposure. Separately, for PTP Obligation bids, PTP Obligation offers, and PTP Option bids, for each source/sink Settlement Point combination, the credit exposure will use the bid price and MW quantity that produces the maximum credit exposure that could result from the CRR Auction for that source/sink Settlement Point combination.

(3) The credit constraint for each Counter-Party is based on the following calculation:

$$\mathbf{ACR}_{b} = \mathbf{AOBLCR}_{b} + \mathbf{AOPTCR}_{b} - \mathbf{AOBLCRO}_{b}$$

Where:

$$\text{AOBLCR}_{b} = \sum_{m} \sum_{h} \sum_{j,\,k} [(\text{BOBLMW}_{m,\,h,(j,\,k),\,b} * (\text{Max}(0,\, \text{BPOBL}_{m,\,h,(j,\,k),\,b}) - \text{Min}(0, \text{A}_{ci99,\,m,\,h,(j,\,k),\,b}, \text{EACP}_{m,\,h,(j,\,k)})))]$$

$$\text{AOPTCR}_{b} = \sum_{m} \sum_{h} \sum_{j,\,k} [(\text{BOPTMW}_{m,\,h,(j,\,k),\,b} * \text{BPOPT}_{m,\,h,(j,\,k),\,b})]$$

$$\text{AOBLCRO}_{b} = \sum_{m} \sum_{h} \sum_{j,\,k} (\text{OOBLMW}_{m,\,h,(j,\,k),\,b} * \text{Min}(0,\, \text{OPOBL}_{m,\,h,(j,\,k),\,b}))$$

The above variables are defined as follows:

Variable	Unit	Description
ACR_{b}	$	*Auction Credit Requirement*—The auction credit requirement for a Counter-Party

		b.
AOBLCR_{b}	\$	*Auction PTP Obligation Credit Requirement*—The auction credit requirement for all PTP Obligation bids submitted by a Counter-Party b for all Operating Days.
$\text{BOBLMW}_{m,\,h,\,(j,\,k),\,b}$	MW	*Awarded Bid PTP Obligation*—The awarded bid PTP Obligation with the source j and sink k for the hour h, and month m submitted by a Counter-Party b.
$\text{BPOBL}_{m,\,h,\,(j,\,k),\,b}$	\$/MW per hour	*Bid Price for PTP Obligation*—Bid Price for PTP Obligation with the source j and sink k for the hour h, and month m submitted by a Counter-Party b.
$\text{A}_{ci\,99,\,m,\,h,\,(j,\,k),\,b}$	\$/MW per hour	*Path-Specific DAM-Based Adder*—The path-specific DAM-based adder with the source j and sink k for the hour h, and month m submitted by a Counter-Party b; calculated as 99th percentile of the average rolling consecutive DAM settled price for the reference CRR source/sink over a period that represents a month for each product type (18 days for 5*16, 8 days for 2*16, 28 days for 7*8). The look-back period for DAM settled prices shall be the lesser of Nodal Market go-live to current time and current time minus three years. If historical Day-Ahead Settlement Point Prices (DASPPs) are not available for a Settlement Point for one or more Operating Days, ERCOT will designate a proxy Settlement Point for this purpose, and the DASPPs of the proxy Settlement Point of corresponding Operating Days are used.
$\text{EACP}_{m,\,h,\,(j,\,k)}$	\$/MW per hour	*Effective Auction Clearing Price*—The auction clearing price with the source j and sink k for the hour h, and month m. For each CRR PTP Obligation, this value is equal to the auction clearing price of an awarded CRR selected as follows: (a) Awarded CRRs with the source j and sink k containing hour h and operating month m are selected from the set of unexpired awarded PTP Obligations. If no awarded CRRs are found the EACP value is zero. (b) If (a) results in more than one awarded CRR, awarded CRRs with the most recent award date are selected. (c) If (b) results in more than one awarded CRR, then the awarded CRR with the lowest auction clearing price is selected.
AOBLCRO_{b}	\$	*Auction PTP Obligation Credit Requirement for Offers*—The auction credit requirement for all PTP Obligation offers submitted by a Counter-Party b for all Operating Days.
$\text{OOBLMW}_{m,\,h,\,(j,\,k),\,b}$	MW	*Awarded Offer PTP Obligation*—The awarded offer PTP Obligation with source j and sink k for the hour h, and month m submitted by a Counter-Party b.
$\text{OPOBL}_{m,\,h,\,(j,\,k),\,b}$	\$/MW per hour	*Offer Price for PTP Obligation*—The offer price for PTP Obligation with the source j and sink k for the hour h, and month m submitted by a Counter-Party b.
AOPTCR_{b}	\$	*Auction PTP Option Bid Credit Requirement*—The auction credit requirement for all PTP Option bids submitted by a Counter-Party b.
$\text{BOPTMW}_{m,\,h,\,(j,\,k),b}$	MW	*Awarded Bid PTP Option*—The awarded bid PTP Option with the source j and sink k for the hour h, and month m submitted by a Counter-Party b.
$\text{BPOPT}_{m,\,h,\,(j,\,k),\,b}$	\$/MW per hour	*Bid Price for PTP Option*—The bid price for PTP Option with the source j and sink k for the hour h, and month m submitted by a Counter-Party b.
b	none	A Counter-Party.
m	none	An operating month.
h	none	An Operating Hour.

j	none	A source Settlement Point.
k	none	A sink Settlement Point.
ci99	none	99th percentile confidence interval.

(4) ERCOT may review preliminary CRR Auction results to ensure that post auction collateral requirements are satisfied for all CRR Account Holders participating in the CRR Auction. If it is practicable to rerun the applicable CRR Auction, and the post CRR Auction collateral requirements for a Counter-Party are not satisfied, ERCOT:

(a) Shall promptly notify the Counter-Party of the amount by which its Financial Security must be increased and allow it until 1500 on the next Bank Business Day from the date on which ERCOT delivered Notification to increase the Financial Security.

(b) If sufficient Financial Security is not received by 1500 on the next Bank Business Day, ERCOT shall void all of the Counter-Party's bids and offers in the CRR Auction and rerun the CRR Auction without that Counter-Party's activity.

(c) ERCOT shall award CRRs in quantities truncated to the nearest tenth MW (0.1 MW).

(d) The CRR clearing price is equal to the corresponding Shadow Price for that CRR product.

(e) Except as noted in paragraph (f) below, when a CRR Account Holder is awarded CRRs as a result of a CRR Auction, the CRRs do not become the property of the winning CRR Account Holder, and the CRRs may not be placed in their CRR accounts, until the required CRR Invoice has been paid.

[NPRR1023: Replace paragraph (e) above with the following upon system implementation:]

(e) When a CRR Account Holder is awarded CRRs as a result of a CRR Auction, the CRRs do not become the property of the winning CRR Account Holder, and the CRRs may not be placed in their CRR accounts, until the required CRR Invoice has been paid.

(f) Following a one-time auction of CRRs pursuant to Section 16.11.6.1.4, Repossession of CRRs by ERCOT, or Section 16.11.6.1.5, Declaration of Forfeit of CRRs, the CRRs may be placed in the account of the winning CRR Account Holder immediately upon determination of the winning bidder if the post-auction collateral requirement is satisfied and if ERCOT determines that the transfer is required to ensure the correctness of the inventory for any subsequent CRR Auction.

[NPRR1023: Delete paragraph (f) above upon system implementation.]

(5) ERCOT shall use a linear programming auction engine model for each CRR Auction that evaluates all CRR Auction bids and CRR Auction offers submitted, and selects a combination of CRR Auction bids and CRR Auction offers that:

(a) Makes the solution simultaneously feasible within the limits of the ERCOT network capability over the auction term; and

(b) Maximizes the objective function, which is equal to the total economic value (as expressed in the CRR Auction bids) of the awarded CRR Auction bids, less the total economic cost (as expressed in CRR Auction offers) of the awarded CRR Auction offers, while observing all applicable constraints.

(6) The CRR Network Model must, to the extent practicable, reflect the continuous and post-contingency system operating limits and operational procedures (i.e., Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs) and Remedial Action Plans (RAPs)) in the Network Operations Model used by ERCOT during Real-Time operations, as discussed below in Section 7.5.5.4, Simultaneous Feasibility Test.

(7) Once a CRR Auction is complete, ERCOT shall archive and keep the CRR Auction system and all models used to finalize the CRR Auction results under ERCOT's data retention policy as that policy applies to data that may be needed to resolve requests for billing adjustments under applicable billing adjustment procedures.

(8) Once a CRR Auction is complete, ERCOT will make available on the MIS Certified Area each active CRR Account Holder's credit exposure calculated within the CRR Auction process (as defined in paragraph (3) above).

7.5.5.4 Simultaneous Feasibility Test

(1) The Simultaneous Feasibility Test (SFT) is a market feasibility test that confirms that the transmission system can support the awarded set of CRRs during normal system conditions, assuming that the Network Operations Model updated with Real-Time network topology is the same as that modeled (for the CRR Auction), while observing all security constraints.

(2) The SFT uses a Direct Current (DC) power-flow model to model the effect of CRR Auction bids and offers on the expected system network topology during the auction term. SFT is not a system reliability test and is not intended to model actual system operating conditions. SFTs are run during the determination of the winning bids and offers for the CRR Auction.

(3) Inputs to the SFT model include:

(a) CRR bids and offers for the auction;

(b) All previously awarded or allocated CRRs for each month;

(c) Transmission line Outage schedules;

(d) Expected configuration of Transmission Facilities, adjusted for oversold CRRs, as specified in paragraph (e) below;

(e) Increased capacity of each element that has been oversold in prior CRR Auctions and CRR allocations to exactly match the amount of CRRs that have been sold or allocated on that element (this ensures the feasibility of the CRR Auction);

(f) Thermal operating limits (including estimates for Dynamic Ratings) for transmission lines;

  (i) For a CRR Long-Term Auction Sequence, ERCOT shall use Dynamic Ratings based on a historical analysis of the maximum peak-hour temperatures for the previous ten years; and

  (ii) For the CRR Monthly Auction, ERCOT shall use Dynamic Ratings for the maximum peak-hour temperature forecast for the month;

(g) Voltage and stability limits that are valid for the study period converted to thermal limits;

(h) ERCOT Transmission Grid pre- and post-contingency ratings;

(i) All Transmission Element contingencies expected to be used by ERCOT in Real-Time operations; and

(j) RAPs, AMPs, and RASs.

7.5.6 CRR Auction Settlements

7.5.6.1 Payment of an Awarded CRR Auction Offer

(1) ERCOT shall pay each CRR Account Holder of its PTP Obligation offers awarded in each CRR Auction. The payment for each source and sink pair for a given Time of Use (TOU) period is calculated as follows:

$$\mathbf{OBLSAMT}_{\mathbf{crrh,\,(j,\,k),\,a}} = \mathbf{(-1) * OBLPR}_{\mathbf{(j,\,k),\,a}} \mathbf{* OBLS}_{\mathbf{crrh,\,(j,\,k),\,a}}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
OBLSAMT $_{crrh,\,(j,\,k),\,a}$	$	*PTP Obligation Sale Amount per CRR Account Holder per source and sink pair per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.

$\text{OBLPR}_{(j,\ k),\ a}$	\$/MWh	*PTP Obligation Price per source and sink pair per CRR Auction*—The clearing price of a PTP Obligation with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
$\text{OBLS}_{crrh,\ (j,\ k),\ a}$	MW	*PTP Obligation Sale per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Obligation offers associated with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hours of the TOU period.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

(2) ERCOT shall pay each CRR Account Holder of its PTP Option offers awarded in each CRR Auction. The payment for each source and sink pair for a given TOU period is calculated as follows:

$$\textbf{OPTSAMT}_{\textbf{crrh, (j, k), a}} = \textbf{(-1) * OPTPR}_{\textbf{(j, k), a}} \textbf{ * OPTS}_{\textbf{crrh, (j, k), a}}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{OPTSAMT}_{crrh,\ (j,\ k),\ a}$	\$	*PTP Option Sale Amount per CRR Account Holder per source and sink pair per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
$\text{OPTPR}_{(j,\ k),\ a}$	\$/MWh	*PTP Option Price per source and sink pair per CRR Auction*—The clearing price of a PTP Option with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
$\text{OPTS}_{crrh,\ (j,\ k),\ a}$	MW	*PTP Option Sale per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hours of the TOU period.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

7.5.6.2 Charge of an Awarded CRR Auction Bid

(1) ERCOT shall charge each CRR Account Holder of its PTP Obligation bids awarded in each CRR Auction. The charge for each source and sink pair for a given Operating Hour is calculated as follows:

$$\textbf{OBLPAMT}_{\textbf{crrh, (j, k), a}} = \textbf{OBLPR}_{\textbf{(j, k), a}} \textbf{ * OBLP}_{\textbf{crrh, (j, k), a}}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{OBLPAMT}_{crrh,\ (j,\ k),\ a}$	\$	*PTP Obligation Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of

Variable	Unit	Definition
		the MW quantity that represents the total PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
$\text{OBLPR}_{(j,\,k),\,a}$	$/MWh	*PTP Obligation Price per source and sink pair per CRR Auction*—The clearing price of a PTP Obligation with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
$\text{OBLP}_{crrh,\,(j,\,k),\,a}$	MW	*PTP Obligation Purchase per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Obligation bids associated with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hours of the TOU period.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

(2) ERCOT shall charge each CRR Account Holder of its PTP Option bids awarded in each CRR Auction. The charge for each source and sink pair for a given TOU period is calculated as follows:

$$\textbf{OPTPAMT}_{\textbf{crrh, (j, k), a}} = \textbf{OPTPR}_{\textbf{(j, k), a}} * \textbf{OPTP}_{\textbf{crrh, (j, k), a}}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{OPTPAMT}_{crrh,\,(j,\,k),\,a}$	$	*PTP Option Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
$\text{OPTPR}_{(j,\,k),\,a}$	$/MWh	*PTP Option Price per source and sink pair per CRR Auction*—The clearing price of a PTP Option with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
$\text{OPTP}_{crrh,\,(j,\,k),\,a}$	MW	*PTP Option Purchase per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Option bids associated with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hours of the TOU period.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

7.5.6.3 Charge of PCRRs Pertaining to a CRR Auction

(1) For pre-assigned PTP Obligations allocated before each CRR Auction, ERCOT shall charge each CRR Account Holder. The charge for each source and sink pair for a given TOU period is calculated as follows:

If $\text{OBLPR}_{(j,\,k),\,a} > 0$

$$\textbf{PCRROBLAMT}_{\textbf{\textit{crrh, (j, k), a, tech}}} = \textbf{PCRROBLF}_{\textbf{\textit{tech}}} * \textbf{OBLPR}_{\textbf{\textit{(j, k), a}}} * \textbf{PCRROBL}_{\textbf{\textit{crrh, (j, k), a, tech}}}$$

Otherwise

$$\mathbf{PCRROBLAMT}_{crrh,\,(j,\,k),\,a,\,tech} = \mathbf{OBLPR}_{(j,\,k),\,a} * \mathbf{PCRROBL}_{crrh,\,(j,\,k),\,a,\,tech}$$

The above variables are defined as follows:

Variable	Unit	Definition
PCRROBLAMT $_{crrh,\,(j,\,k),\,a,\,tech}$	$	*PCRR PTP Obligation Amount per CRR Account Holder per source and sink pair per CRR Auction by resource technology*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Obligations associated with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hour.
PCRROBLF $_{tech}$		*PCRR PTP Obligation pricing Factor per resource technology*—The pricing factor of pre-allocated PTP Obligations based on Resources of the technology *tech*. See item (1)(g)(ii) of Section 7.4.2.2, PCRR Allocations and Nominations.
OBLPR $_{(j,\,k),\,a}$	$/MWh	*PTP Obligation Price per source and sink pair per CRR Auction*—The clearing price of a PTP Obligation with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
PCRROBL $_{crrh,\,(j,\,k),\,a,\,tech}$	MW	*PCRR PTP Obligation per CRR Account Holder per source and sink pair per CRR Auction by resource technology*—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Obligations associated with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hours of the TOU period.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
tech	none	A Resource technology. See item (1)(g) of Section 7.4.2.2.

(2) For pre-assigned PTP Options allocated before each CRR Auction, ERCOT shall charge each CRR Account Holder. The charge for each source and sink pair for a given TOU period is calculated as follows:

$$\mathbf{PCRROPTAMT}_{crrh,\,(j,\,k),\,a,\,tech} = \mathbf{PCRROPTF}_{tech} * \mathbf{OPTPR}_{(j,\,k),\,a} * \mathbf{PCRROPT}_{crrh,\,(j,\,k),\,a,\,tech}$$

The above variables are defined as follows:

Variable	Unit	Definition
PCRROPTAMT $_{crrh,\,(j,\,k),\,a,\,tech}$	$	*PCRR PTP Option Amount per CRR Account Holder per source and sink pair per CRR Auction by resource technology*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Options associated with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hour.
PCRROPTF $_{tech}$		*PCRR PTP Option pricing Factor per resource technology*—The pricing factor of pre-allocated PTP Options based on Resources of the technology *tech*. See item (1)(g)(i) of Section 7.4.2.2.
OPTPR $_{(j,\,k),\,a}$	$/MWh	*PTP Option Price per source and sink pair per CRR Auction*—The clearing price of a PTP Option with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
PCRROPT $_{crrh,\,(j,\,k),\,a,\,tech}$	MW	*PCRR PTP Option per CRR Account Holder per source and sink pair per*

Variable	Unit	Definition
		CRR Auction by resource technology—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Options with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hours of the TOU period.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
tech	none	A Resource technology. See item (1)(g) of Section 7.4.2.2.

7.5.6.4 CRR Auction Revenues

(1) The revenue for a given month produced from CRRs that source and sink within the same 2003 ERCOT Congestion Management Zone (CMZ), cleared in each CRR Auction, is calculated as follows:

$$\mathbf{CRRZREV}_{z,\,a} = \sum_{h}\Big(\sum_{crrh}\sum_{j}\sum_{k}\mathbf{OBLSAMT}_{crrh,(j,k),z,a,h} + \sum_{crrh}\sum_{j}\sum_{k}\mathbf{OPTSAMT}_{crrh,(j,k),z,a,h} + \sum_{crrh}\sum_{j}\sum_{k}\mathbf{OBLPAMT}_{crrh,(j,k),z,a,h} + \sum_{crrh}\sum_{j}\sum_{k}\mathbf{OPTPAMT}_{crrh,(j,k),z,a,h}\Big)$$

The above variables are defined as follows:

Variable	Unit	Definition
$\mathrm{CRRZREV}_{z,\,a}$	$	*CRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the CRRs that source and sink in CMZ *z*, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
$\mathrm{OBLSAMT}_{crrh,\,(j,\,k),\,z,\,a,\,h}$	$	*PTP Obligation Sale Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per hour*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
$\mathrm{OPTSAMT}_{crrh,\,(j,\,k),\,z,\,a,\,h}$	$	*PTP Option Sale Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per hour*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
$\mathrm{OBLPAMT}_{crrh,\,(j,\,k),\,z,\,a,\,h}$	$	*PTP Obligation Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
$\mathrm{OPTPAMT}_{crrh,\,(j,\,k),\,z,\,a,\,h}$	$	*PTP Option Purchase Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option

Variable	Unit	Definition
		bids awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
a	none	A CRR Auction.
z	none	A 2003 ERCOT CMZ.
crrh	none	A CRR Account Holder that paid the invoice in full.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
h	none	An hour in the month.

(2) The revenue for a given month produced from CRRs that source and sink in different 2003 ERCOT CMZs, cleared in each CRR Auction, is calculated as follows:

$$\textbf{CRRNZREV}_{a} = \sum_{h}\Big(\sum_{crrh}\sum_{j}\sum_{k}\textbf{OBLSAMT}_{crrh,(j,k),a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OPTSAMT}_{crrh,(j,k),a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OBLPAMT}_{crrh,(j,k),a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OPTPAMT}_{crrh,(j,k),a,h}\Big)$$

The above variables are defined as follows:

Variable	Unit	Definition
CRRNZREV_{a}	$	*CRR Non-Zonal Revenue*—The revenue resulted from the CRRs that source and sink in different CMZs, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
$\text{OBLSAMT}_{crrh,\,(j,\,k),\,a,\,h}$	$	*PTP Obligation Sale Amount per CRR Account Holder per source and sink pair per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
$\text{OPTSAMT}_{crrh,\,(j,\,k),\,a,\,h}$	$	*PTP Option Sale Amount per CRR Account Holder per source and sink pair per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
$\text{OBLPAMT}_{crrh,\,(j,\,k),\,a,\,h}$	$	*PTP Obligation Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
$\text{OPTPAMT}_{crrh,\,(j,\,k),\,a,\,h}$	$	*PTP Option Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
a	none	A CRR Auction.
crrh	none	A CRR Account Holder that paid the invoice in full.
(j, k)	none	A pair of source and sink Settlement Points in different CMZs.

Variable	Unit	Definition
h	none	An hour in the month.

(3) The revenue for a given month produced from PCRRs that source and sink within the same 2003 ERCOT CMZ, pertaining to each CRR Auction, is calculated as follows:

$$\mathbf{PCRRZREV}_{z,\,a} = \sum_{h} \Big(\sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \mathbf{PCRROBLAMT}_{crrh,(j,k),z,a,tech,h} + \sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \mathbf{PCRROPTAMT}_{crrh,(j,k),z,a,tech,h} \Big)$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{PCRRZREV}_{z,\,a}$	$	*PCRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the PCRRs that source and sink in CMZ *z*, pertaining to CRR Auction *a*, for the month.
$\text{PCRROBLAMT}_{crrh,\,(j,\,k),\,z,\,a,\,tech,\,h}$	$	*PCRR PTP Obligation Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Obligations pertaining to CRR Auction *a* with the source *j* and the sink *k* in CMZ *z*, based on Resources of the technology *tech*, for the hour *h*.
$\text{PCRROPTAMT}_{crrh,\,(j,\,k),\,z,\,a,\,tech,\,h}$	$	*PCRR PTP Option Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Options pertaining to CRR Auction *a* with the source *j* and the sink *k* in CMZ *z*, based on Resources of the technology *tech*, for the hour *h*.
a	none	A CRR Auction.
z	none	A 2003 ERCOT CMZ.
crrh	none	A CRR Account Holder that paid the invoice in full.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
tech	none	A Resource technology.
h	none	An hour in the month.

(4) The revenue for a given month produced from PCRRs that source and sink in different 2003 ERCOT CMZs, pertaining to each CRR Auction, is calculated as follows:

$$\mathbf{PCRRNZREV}_{a} = \sum_{h} \Big(\sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \mathbf{PCRROBLAMT}_{crrh,(j,k),a,tech,h} + \sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \mathbf{PCRROPTAMT}_{crrh,(j,k),a,tech,h} \Big)$$

The above variables are defined as follows:

Variable	Unit	Definition

$PCRRNZREV_{a}$	$	*PCRR Non-Zonal Revenue per CRR Auction*—The revenue resulted from the PCRRs that source and sink in different CMZs, pertaining to CRR Auction *a*, for the month.
$PCRROBLAMT_{crrh,\ (j,\ k),\ a,\ tech,\ h}$	$	*PCRR PTP Obligation Amount per CRR Account Holder per source and sink pair per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Obligations pertaining to CRR Auction *a* with the source *j* and the sink *k* in different CMZs, based on Resources of the technology *tech*, for the hour *h*.
$PCRROPTAMT_{crrh,\ (j,\ k),\ a,\ tech,\ h}$	$	*PCRR PTP Option Amount per CRR Account Holder per source and sink pair per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Options pertaining to CRR Auction *a* with the source *j* and the sink *k* in different CMZs, based on Resources of the technology *tech*, for the hour *h*.
a	none	A CRR Auction.
crrh	none	A CRR Account Holder that paid the invoice in full.
(j, k)	none	A pair of source and sink Settlement Points in different CMZs.
tech	none	A Resource technology.
h	none	An hour in the month.

7.5.7 Method for Distributing CRR Auction Revenues

(1) ERCOT shall determine, for each month, the CRR Monthly Revenues (CMRs). The CMR is the sum of:

(a) Monthly CRR revenue for that month; and

(b) PCRR revenues.

(2) ERCOT shall credit the net CRR Auction revenue (including PCRR revenue) produced from CRRs cleared in each CRR Auction that source from a Settlement Point located within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ to Qualified Scheduling Entities (QSEs) in the 2003 ERCOT CMZ on a zonal Load Ratio Share (LRS) basis. All other net CRR Auction revenues must be allocated to QSEs on an ERCOT-wide LRS basis. For these allocation purposes, any Non-Opt-In Entity (NOIE) Load Zone is considered to be located entirely within the 2003 ERCOT CMZ that represented the largest Load for that NOIE or group of NOIEs in 2003.

[NPRR1030: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall credit the net CRR Auction revenue (including PCRR revenue) produced from CRRs cleared in each CRR Auction that source from a Settlement Point located within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ to Qualified Scheduling Entities (QSEs) in the 2003 ERCOT CMZ on a zonal ratio share basis. All other net CRR Auction revenues must be allocated to QSEs on an ERCOT-wide ratio share basis. For these allocation purposes, any Non-Opt-In Entity (NOIE) Load Zone is considered to be located entirely within the 2003 ERCOT

CMZ that represented the largest Load for that NOIE or group of NOIEs in 2003.

(3) For initial distribution of CMRs, revenues shall be paid to each QSE based on that QSE's LRS in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

[NPRR1030: Replace paragraph (3) above with the following upon system implementation:]

(3) For initial distribution of CMRs, revenues shall be paid to each QSE based on that QSE's DC Tie ratio share for the month. Remaining revenues shall be paid to each QSE based on that QSE's ratio share, excluding DC Tie exports, in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

(4) ERCOT shall true up the distribution of CMRs based on that QSE's LRS in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month in accordance with paragraph (2) of Section 9.10, CRR Auction Revenue Distribution Invoices.

[NPRR1030: Replace paragraph (4) above with the following upon system implementation:]

(4) ERCOT shall true up the distribution of CMRs, in accordance with paragraph (2) of Section 9.10, CRR Auction Revenue Distribution Invoices, based on that QSE's DC Tie ratio share for the month. Remaining revenues shall be paid to each QSE based on that QSE's ratio share, excluding DC Tie exports, in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

(5) The net CRR Auction revenue produced from CRRs cleared and paid for in each CRR Auction that source from a Settlement Point within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ shall be distributed on a zonal LRS basis. The portion of the net monthly CRR Auction revenue to be distributed to each QSE with Load in that zone for a given month is calculated as follows:

$$\textbf{LACMRZAMT}_{z,\,q} = \quad (-1) * \sum_{a} (\textbf{CRRZREV}_{z,\,a} + \textbf{PCRRZREV}_{z,\,a}) * \textbf{MLRSZ}_{z,\,q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LACMRZAMT $_{z,\,q}$	$	*Load-Allocated CRR Monthly Revenue Zonal Amount per zone per QSE*—The payment to QSE *q* of the revenues resulted from the CRRs that source and sink in CMZ *z*, for the month.
CRRZREV $_{z,\,a}$	$	*CRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the CRRs that source and sink in CMZ *z*, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
PCRRZREV $_{z,\,a}$	$	*PCRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the PCRRs that source and sink in CMZ *z*, pertaining to CRR Auction *a*, for the month.

Variable	Unit	Definition
$MLRSZ_{q,z}$	none	*Monthly Load Ratio Share Zonal per QSE per zone*—The LRS of QSE *q* for its Load in CMZ *z*, for the peak-Load 15-minute Settlement Interval in the month.
q	none	A QSE.
z	none	A 2003 ERCOT CMZ.
a	none	A CRR Auction.

[NPRR1030 and NPRR1054: Replace applicable portions of paragraph (5) above with the following upon system implementation:]

(5) The net CRR Auction revenue produced from CRRs cleared and paid for in each CRR Auction that source from a Settlement Point within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ shall be distributed on a zonal ratio share basis. The portion of the net monthly CRR Auction revenue to be distributed to each QSE with Load in that zone for a given month is calculated as follows:

$$\mathbf{LACMRZAMT_{z,q} = (-1) * (CMRZDC_{z,q} + CMRZNDC_{z,q})}$$

Where:

$$CMRZNDC_{z,q} = (\sum_{a}(CRRZREV_{z,a} + PCRRZREV_{z,a}) - \sum_{q} CMRZDC_{z,q}) * MLRSZ_{z,q}$$

$$CMRZDC_{z,q} = \sum_{a}(CRRZREV_{z,a} + PCRRZREV_{z,a}) * DCMLRSZ_{z,q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LACMRZAMT_{z,q}$	$	*Load-Allocated CRR Monthly Revenue Zonal Amount per zone per QSE*—The sum payment to QSE *q* representing Loads and DC Tie exports of the revenues resulted from the CRRs that source and sink in CMZ *z*, for the month.
$CMRZDC_{z,q}$	$	*CRR Monthly Revenue Zonal Amount for DC Tie Exports per zone per QSE*—The amount due to QSE *q* representing DC Tie exports of the revenues resulted from the CRRs that source and sink in CMZ *z*, for the month.
$CMRZNDC_{z,q}$	$	*CRR Monthly Revenue Zonal Amount for Non-DC Tie Loads per zone per QSE*—The amount due to QSE *q* representing Loads (excluding DC Tie exports) of the revenues resulted from the CRRs that source and sink in CMZ *z*, for the month.
$CRRZREV_{z,a}$	$	*CRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the CRRs that source and sink in CMZ *z*, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
$PCRRZREV_{z,a}$	$	*PCRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the PCRRs that source and sink in CMZ *z*, pertaining to CRR Auction *a*, for the month.
$DCMLRSZ_{q,z}$	none	*DC Tie Exports Monthly Load Ratio Share Zonal per QSE per zone*—The ratio share calculated for QSE *q* with DC Tie exports in CMZ *z*, for the month. See Section 6.6.2.8, QSE DC Tie Export Load Ratio Share by Congestion Management Zone for a Month.
$MLRSZ_{q,z}$	none	*Monthly Load Ratio Share Zonal per QSE per zone*—The ratio share of QSE *q* for its Load excluding DC Tie exports in CMZ *z*, for the peak Load 15-minute

		Settlement Interval in the month.
q	none	A QSE.
z	none	A 2003 ERCOT CMZ.
a	none	A CRR Auction.

(6) The net CRR Auction revenue produced from CRRs cleared and paid for in each CRR Auction that do not source from a Settlement Point within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ shall be distributed on an ERCOT-wide LRS basis. The portion of the net monthly CRR Auction Revenue Amount (from CRRs with paths that cross the 2003 ERCOT CMZ boundaries) to be distributed for a given month is calculated as follows:

$$\textbf{LACMRNZAMT}_{q} = (-1) * \sum_{a} (\textbf{CRRNZREV}_{a} + \textbf{PCRRNZREV}_{a}) * \textbf{MLRS}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LACMRNZAMT $_q$	$	*Load-Allocated CRR Monthly Revenue Non-Zonal Amount per QSE*—The payment to QSE q of the revenues resulted from the CRRs that source and sink in different CMZs, for the month.
CRRNZREV $_a$	$	*CRR Zonal Revenue per CRR Auction*—The revenue resulted from the CRRs that source and sink in different CMZs, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction a, for the month.
PCRRNZREV $_a$	$	*PCRR Zonal Revenue per CRR Auction*—The revenue resulted from the PCRRs that source and sink in different CMZs, pertaining to CRR Auction a, for the month.
MLRS $_q$	none	*Monthly Load Ratio Share per QSE*—The LRS calculated for QSE q for the peak-Load 15-minute Settlement Interval in the month. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
a	none	A CRR Auction.

[NPRR1030: Replace paragraph (6) above with the following upon system implementation:]

(6) The net CRR Auction revenue produced from CRRs cleared and paid for in each CRR Auction that do not source from a Settlement Point within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ shall be distributed on an ERCOT-wide ratio share basis. The portion of the net monthly CRR Auction Revenue Amount (from CRRs with paths that cross the 2003 ERCOT CMZ boundaries) to be distributed for a given month is calculated as follows:

$$\textbf{LACMRNZAMT}_{q} = (-1) * (\textbf{CMRNZDC}_{q} + \textbf{CMRNZNDC}_{q})$$

Where:

$$\text{CMRNZNDC}_{q} = (\sum_{a} (\text{CRRNZREV}_{a} + \text{PCRRNZREV}_{a}) - \sum_{q} \text{CMRNZDC}_{q}) * \text{MLRS}_{q}$$

$$\text{CMRNZDC}_q = \sum_a (\text{CRRNZREV}_a + \text{PCRRNZREV}_a) * \text{DCMLRS}_q$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LACMRNZAMT_q	$	*Load-Allocated CRR Monthly Revenue Non-Zonal Amount per QSE*—The sum payment to QSE *q* representing Loads and DC Tie exports of the revenues resulted from the CRRs that source and sink in different CMZs, for the month.
CMRNZDC_q	$	*CRR Monthly Revenue Non-Zonal Amount for DC Tie Exports per QSE*—The amount due to QSE *q* representing DC Tie exports of the revenues resulted from the CRRs that source and sink in different CMZs, for the month.
CMRNZNDC_q	$	*CRR Monthly Revenue Non-Zonal Amount for Non-DC Tie Loads per QSE*—The amount due to QSE *q* representing Loads (excluding DC Tie exports) of the revenues resulted from the CRRs that source and sink in different CMZs, for the month.
CRRNZREV_a	$	*CRR Zonal Revenue per CRR Auction*—The revenue resulted from the CRRs that source and sink in different CMZs, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
PCRRNZREV_a	$	*PCRR Zonal Revenue per CRR Auction*—The revenue resulted from the PCRRs that source and sink in different CMZs, pertaining to CRR Auction *a*, for the month.
DCMLRS_q	none	*DC Tie Monthly Load Ratio Share per QSE*—The ratio share calculated for QSE *q* with DC Tie exports for the calendar month. See Section 6.6.2.6, QSE DC Tie Export Load Ratio Share for a Month.
MLRS_q	none	*Monthly Load Ratio Share per QSE* —The ratio share of Loads excluding DC Tie exports for QSE *q* for the peak Load 15-minute Settlement Interval.
q	none	A QSE.
a	none	A CRR Auction.

7.6 CRR Balancing Account

(1) In the Day-Ahead Market (DAM), if the congestion rent is equal to or greater than the net amounts due to all Congestion Revenue Right (CRR) Owners for any Settlement Interval, then ERCOT shall pay the net amounts due to the CRR Owners and put any excess amount into the CRR Balancing Account (CRRBA).

(2) In the DAM, if the congestion rent is less than the net amounts due to all CRR Owners for any Settlement Interval, then ERCOT shall short-pay each CRR Owner on a prorated basis and shall keep track of how much each CRR Owner has been short-paid. The proration must be calculated using only the amounts due to the CRR Owner for CRRs settled in both the DAM and Real-Time and not using amounts due to ERCOT for Point-to-Point (PTP) Obligations owned by the CRR Owner.

(3) ERCOT shall pay any positive balance in the CRRBA to each short-paid CRR Owner, with the amount paid to each CRR Owner being the lesser of (a) a prorated amount based on the short-paid amount for that CRR Owner compared to the total short-paid amount, and (b) the short-paid amount for that CRR Owner. Any remaining positive balance in the CRRBA will first be used to fund the CRRBA fund up to the fund cap, as described

in Section 7.9.3.5, CRR Balancing Account Closure, and any surplus must be allocated to all Qualified Scheduling Entities (QSEs) on the QSE's Load Ratio Share (LRS) in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

[NPRR1030: Replace paragraph (3) above with the following upon system implementation:]

(3) ERCOT shall pay any positive balance in the CRRBA to each short-paid CRR Owner, with the amount paid to each CRR Owner being the lesser of (a) a prorated amount based on the short-paid amount for that CRR Owner compared to the total short-paid amount, and (b) the short-paid amount for that CRR Owner. Any remaining positive balance in the CRRBA will first be used to fund the CRRBA fund up to the fund cap, as described in Section 7.9.3.5, CRR Balancing Account Closure, and any surplus must be allocated to all Qualified Scheduling Entities (QSEs) based on the QSE's ratio shares for the month.

(4) For initial distribution of the CRRBA, revenues shall be paid to each QSE based on that QSE's LRS in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

[NPRR1030: Replace paragraph (4) above with the following upon system implementation:]

(4) For initial distribution of the CRRBA, revenues shall be paid to each QSE based on that QSE's Direct Current Tie (DC Tie) monthly ratio share for the month. Remaining revenues shall be paid to each QSE based on that QSE's ratio share, excluding DC Tie exports, in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

(5) ERCOT shall true up the distribution of CRRBA based on that QSE's LRS in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month in accordance with paragraph (2) of Section 9.12, CRR Balancing Account Invoices.

[NPRR1030: Replace paragraph (5) above with the following upon system implementation:]

(5) ERCOT shall true up the distribution of CRRBA, in accordance with paragraph (2) of Section 9.12, CRR Balancing Account Invoices, based on that QSE's DC Tie monthly ratio share for the month. Remaining revenues shall be paid to each QSE based on that QSE's ratio share, excluding DC Tie exports, in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

7.7 Point-to-Point (PTP) Option Award Charge

7.7.1 Determination of the PTP Option Award Charge

(1) ERCOT will calculate a Point-to-Point (PTP) Option Award Charge for each Congestion Revenue Right (CRR) Account Holder for each PTP Option bid awarded where the clearing price for the PTP Option bid awarded is less than the Minimum PTP Option Bid Price.

(2) The Technical Advisory Committee (TAC) shall review the current Minimum PTP Option Bid Price at least annually and may recommend to the ERCOT Board a change to this value by submitting a Nodal Protocol Revision Request (NPRR).

(3) ERCOT shall charge each CRR Account Holder for its PTP Option bids awarded in each CRR Auction as follows:

$$\mathbf{OPTAFAMT}_{\mathit{crrh,\,a}} = \sum_{bp} \sum_{h} \sum_{(j,k)} (\mathbf{Max\ (0,\ OPTMBP\ -\ OPTPR}_{\mathit{(j,\,k),\,a,\,h,\,bp}}) * \mathbf{OPTP}_{\mathit{crrh,\,(j,\,k),\,a,\,h,\,bp}})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\mathrm{OPTAFAMT}_{crrh,\,a}$	$	*PTP Option Award Charge Amount per CRR Account Holder per CRR Auction*—The charge assessed to CRR Account Holder *crrh* for PTP Option awards awarded in CRR Auction *a*, for the hour for which the clearing price is less than the defined Minimum PTP Option Bid Price. For a multi-month CRR Auction, the charge shall be calculated for each month.
OPTMBP	$/MW per hour	*Minimum PTP Option Bid Price*—As defined in Section 2.1, Definitions.
$\mathrm{OPTPR}_{(j,\,k),\,a,\,h,\,bp}$	$/MW per hour	*PTP Option Price per source and sink pair per CRR Auction*—The clearing price of a PTP Option with the source *j* and the sink *k* in CRR Auction *a*, for the hour *h*, for the bid period *bp*.
$\mathrm{OPTP}_{crrh,\,(j,\,k),\,a,\,h,\,bp}$	MW	*PTP Option Purchase per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Option bids associated with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, for the bid period *bp*.
crrh	None	A CRR Account Holder.
j	None	A source Settlement Point.
k	None	A sink Settlement Point.
a	None	A CRR Auction.
h	None	An Operating Hour.
bp	None	A CRR bid period.

7.7.2 [RESERVED]

7.8 Bilateral Trades and ERCOT CRR Registration System

(1) Market Participants may sell or trade Point-to-Point (PTP) Options and PTP Obligations bilaterally, except PTP Options with Refund and PTP Obligations with Refund.

(2) The characteristics of the Congestion Revenue Rights (CRRs) sold or traded bilaterally, including CRR source and CRR sink and time-of-use block, may not be modified from the terms of the original CRR.

(3) ERCOT shall initially populate a database of CRR Owners with the first-buyers of CRRs and first-recipients of Pre-Assigned Congestion Revenue Rights (PCRRs).

(4) A transfer of CRRs through the ERCOT CRR registration system is not effective until the selling CRR Account Holder reports the transaction, the buying CRR Account Holder acknowledges the transaction, and both parties meet ERCOT's credit requirements to support the transfer. Until all of those occur, the selling CRR Account Holder is considered the CRR Owner for purposes of these Protocols, including financial responsibility.

(5) For CRR ownership to be effective in the Day-Ahead Market (DAM), the CRR must be registered through the ERCOT CRR registration system prior to the DAM. PTP Obligations acquired in DAM may not change ownership in the ERCOT CRR registration system after DAM execution.

7.9 CRR Settlements

7.9.1 Day-Ahead CRR Payments and Charges

7.9.1.1 Payments and Charges for PTP Obligations Settled in DAM

(1) Except as specified in paragraph (2) below, ERCOT shall pay or charge the owner of each Point-to-Point (PTP) Obligation based on the difference in the Day-Ahead Settlement Point Price between the sink Settlement Point and the source Settlement Point.

(2) For PTP Obligations that have a positive value and sink at a Resource Node, the PTP Obligation payment may be reduced due to directional network elements that are oversold in previous Congestion Revenue Right (CRR) Auctions.

(3) The payment or charge to each CRR Owner for a given Operating Hour of PTP Obligations with each pair of source and sink Settlement Points settled in the Day-Ahead Market (DAM) is calculated as follows:

If the PTP Obligation has a non-positive value, i.e. ($DAOBLPR_{(j, k)} \leq 0$), or the sink, *k,* is a Load Zone or Hub, then

$$\mathbf{DAOBLAMT}_{o, (j, k)} = \mathbf{(-1) * DAOBLTP}_{o, (j, k)}$$

If the PTP Obligation has a positive value and the sink is a Resource Node, then

$$\mathbf{DAOBLAMT}_{o, (j, k)} = \mathbf{(-1) * Max\ ((DAOBLTP}_{o, (j, k)} \mathbf{- DAOBLDA}_{o, (j, k)}\mathbf{), Min\ (DAOBLTP}_{o, (j, k)}\mathbf{, DAOBLHV}_{o, (j, k)}\mathbf{))}$$

Where:

The target payment:
$DAOBLTP_{o, (j, k)} = DAOBLPR_{(j, k)} * DAOBL_{o, (j, k)}$

The price based on the difference of the Settlement Point Prices:
$DAOBLPR_{(j, k)} = DASPP_k - DASPP_j$

The derated amount:
$DAOBLDA_{o, (j, k)} = OBLDRPR_{(j, k)} * DAOBL_{o, (j, k)}$

The price used to calculate the derated amount:
$OBLDRPR_{(j, k)} = \sum_{c} (Max\ (0, DAWASF_{j, c} - DAWASF_{k, c}) * DASP_c * DRF_c)$

The hedge value:
$DAOBLHV_{o, (j, k)} = DAOBLHVPR_{(j, k)} * DAOBL_{o, (j, k)}$

The price of the hedge value:
If the source, *j*, is a Load Zone or Hub and the sink, *k*, is a Resource Node,
$DAOBLHVPR_{(j, k)} = Max\ (0, MAXRESPR_k - DASPP_j)$

If the source, *j*, is a Resource Node and the sink, *k*, is also a Resource Node,
$DAOBLHVPR_{(j, k)} = Max\ (0, MAXRESPR_k - MINRESPR_j)$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$DAOBLAMT_{o, (j, k)}$	$	*Day-Ahead Obligation Amount per CRR Owner per source and sink pair*—The payment or charge to CRR Owner *o* for the PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOBLTP_{o, (j, k)}$	$	*Day-Ahead Obligation Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOBLHV_{o, (j, k)}$	$	*Day-Ahead Obligation Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOBLDA_{o, (j, k)}$	$	*Day-Ahead Obligation Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.

Variable	Unit	Definition
$\text{DAOBLPR}_{(j,\,k)}$	$/MW per hour	*Day-Ahead Obligation Price per source and sink pair*—The DAM price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
DASPP_{j}	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j*, for the hour.
DASPP_{k}	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k*, for the hour.
$\text{OBLDRPR}_{(j,\,k)}$	$/MW per hour	*Obligation Deration Price per source and sink pair*—The deration price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
DASP_{c}	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF_{c}	none	*Deration Factor per constraint*—The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
$\text{DAWASF}_{j,\,c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the directional network element for constraint *c*, in the hour.
$\text{DAWASF}_{k,\,c}$	None	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the directional network element for constraint *c*, in the hour.
$\text{DAOBLHVPR}_{(j,\,k)}$	$/MWh	*Day-Ahead Obligation Hedge Value Price per source and sink pair*—The Day-Ahead hedge price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
MINRESPR_{j}	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for the Resources located at the source Settlement Point *j*.
MAXRESPR_{k}	$/MWh	*Max Resource Price for sink*—The highest Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
$\text{DAOBL}_{o,\,(j,\,k)}$	MW	*Day-Ahead Obligation per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A constraint associated with a directional network element for the hour.

(4) The net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations settled in the DAM is calculated as follows:

$$\textbf{DAOBLAMTOTOT}_{\boldsymbol{o}} = \textbf{DAOBLCROTOT}_{\boldsymbol{o}} + \textbf{DAOBLCHOTOT}_{\boldsymbol{o}}$$

Where:

$$\text{DAOBLCROTOT}_{o} = \sum_{j} \sum_{k} \text{Min}\ (0, \text{DAOBLAMT}_{o,\,(j,\,k)})$$

$$\text{DAOBLCHOTOT}_{o} = \sum_{j} \sum_{k} \text{Max}\ (0, \text{DAOBLAMT}_{o,\,(j,\,k)})$$

The above variables are defined as follows:

Variable	Unit	Definition
DAOBLAMTOTOT_{o}	$	*Day-Ahead Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* for all its PTP Obligations settled in the DAM, for the hour.
DAOBLCROTOT_{o}	$	*Day-Ahead Obligation Credit Owner Total per CRR Owner*—The total payment to CRR Owner *o* for its PTP Obligations settled in the DAM, for the hour.
DAOBLCHOTOT_{o}	$	*Day-Ahead Obligation Charge Owner Total per CRR Owner*—The total charge to CRR Owner *o* for its PTP Obligations settled in the DAM, for the hour.
$\text{DAOBLAMT}_{o, (j, k)}$	$	*Day-Ahead Obligation Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for its PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.1.2 Payments for PTP Options Settled in DAM

(1) Except as specified otherwise in paragraph (2) below, ERCOT shall pay the owner of a PTP Option the difference in the Day-Ahead Settlement Point Price between the sink Settlement Point and the source Settlement Point, if positive.

(2) For PTP Options that sink at a Resource Node, the PTP Option payment may be reduced due to Transmission Elements that are oversold in previous CRR Auctions.

(3) The payment to each CRR Owner for a given Operating Hour of PTP Options with each pair of source and sink Settlement Points settled in the DAM is calculated as follows:

If the sink, *k*, is a Load Zone or Hub, then

$$\mathbf{DAOPTAMT}_{\boldsymbol{o, (j, k)}} = \mathbf{(-1) * DAOPTTP}_{\boldsymbol{o, (j, k)}}$$

If the sink, *k*, is a Resource Node, then

$$\mathbf{DAOPTAMT}_{\boldsymbol{o, (j, k)}} = \mathbf{(-1) * Max\ ((DAOPTTP}_{\boldsymbol{o, (j, k)}} - \mathbf{DAOPTDA}_{\boldsymbol{o, (j, k)}}\mathbf{), Min\ (DAOPTTP}_{\boldsymbol{o, (j, k)}}\mathbf{, DAOPTHV}_{\boldsymbol{o, (j, k)}}\mathbf{))}$$

Where:

The target payment:
$\text{DAOPTTP}_{o, (j, k)} = \text{DAOPTPR}_{(j, k)} * \text{OPT}_{o, (j, k)}$

The price based on the difference of the Settlement Point Prices:
$\text{DAOPTPR}_{o, (j, k)} = \text{Max}\ (0, \text{DASPP}_{k} - \text{DASPP}_{j})$

The derated amount:
$\text{DAOPTDA}_{o, (j, k)} = \text{OPTDRPR}_{(j, k)} * \text{OPT}_{o, (j, k)}$

The price used to calculate the derated amount:

$$\text{OPTDRPR}_{(j,\,k)} = \sum_{c} (\text{Max}\ (0, \text{DAWASF}_{j,\,c} - \text{DAWASF}_{k,\,c}) * \text{DASP}_{c} * \text{DRF}_{c})$$

The hedge value:

$$\text{DAOPTHV}_{o,\,(j,\,k)} = \text{DAOPTHVPR}_{(j,\,k)} * \text{OPT}_{o,\,(j,\,k)}$$

The price of the hedge value:

If the source, *j*, is a Load Zone or Hub and the sink, *k*, is a Resource Node,

$$\text{DAOPTHVPR}_{(j,\,k)} = \text{Max}\ (0, \text{MAXRESPR}_{k} - \text{DASPP}_{j})$$

If the source, *j*, is a Resource Node and the sink, *k*, is also a Resource Node,

$$\text{DAOPTHVPR}_{(j,\,k)} = \text{Max}\ (0, \text{MAXRESPR}_{k} - \text{MINRESPR}_{j})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{DAOPTAMT}_{o,\,(j,\,k)}$	$	*Day-Ahead Option Amount per CRR Owner per source and sink pair*—The payment to CRR Owner *o* for the PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
$\text{DAOPTTP}_{o,\,(j,\,k)}$	$	*Day-Ahead Option Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
$\text{DAOPTHV}_{o,\,(j,\,k)}$	$	*Day-Ahead Option Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
$\text{DAOPTDA}_{o,\,(j,\,k)}$	$	*Day-Ahead Option Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
$\text{DAOPTPR}_{(j,\,k)}$	$/MW per hour	*Day-Ahead Option Price per source and sink pair*—The DAM price of a PTP Option with the source *j* and the sink *k*, for the hour.
DASPP_{j}	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j*, for the hour.
DASPP_{k}	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k*, for the hour.
$\text{OPTDRPR}_{(j,\,k)}$	$/MW per hour	*Option Deration Price per source and sink pair*—The deration price of a PTP Option with the source *j* and the sink *k*, for the hour.
DASP_{c}	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF_{c}	none	*Deration Factor per constraint*—The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
$\text{DAWASF}_{j,\,c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the directional network element for constraint *c*, in the hour.
$\text{DAWASF}_{k,\,c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the directional network element for constraint *c*, in the hour.

Variable	Unit	Definition
$\text{DAOPTHVPR}_{(j,\ k)}$	\$/MWh	*Day-Ahead Option Hedge Value Price per source and sink pair*—The Day-Ahead hedge price of a PTP Option with the source *j* and the sink *k*, for the hour.
MINRESPR_{j}	\$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for Resources located at the source Settlement Point *j*.
MAXRESPR_{k}	\$/MWh	*Max Resource Price for sink*—The highest Maximum Resource Price for Resources located at the sink Settlement Point *k*.
$\text{OPT}_{o,\ (j,\ k)}$	MW	*Option per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A constraint associated with a directional network element for the hour.

(4) The total payment to each CRR Owner for the Operating Hour of all its PTP Options settled in the DAM is calculated as follows:

$$\mathbf{DAOPTAMTOTOT}_{o} = \sum_{j}\sum_{k} \mathbf{DAOPTAMT}_{o,\ (j,\ k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAOPTAMTOTOT_{o}	\$	*Day-Ahead Option Amount Owner Total per CRR Owner*—The total payment to CRR Owner *o* for all its PTP Options settled in the DAM, for the hour.
$\text{DAOPTAMT}_{o,\ (j,\ k)}$	\$	*Day-Ahead Option Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for its PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(5) For informational purposes, the following calculation of PTP Option value shall be posted on the ERCOT website:

$$\mathbf{DAOPTPRINFO}_{(j,\ k)} = \sum_{c} (\mathbf{DASP}_{c} * \mathbf{Max}\ (0, (\mathbf{DAWASF}_{j,\ c} - \mathbf{DAWASF}_{k,\ c})))$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DAOPTPRINFO}_{(j,\ k)}$	\$/MW per hour	*Day-Ahead Option Informational Price per pair of source and sink*—The informational DAM price of the PTP Options with the source Settlement Point *j* and the sink Settlement Point *k*, for the hour.
$\text{DAWASF}_{j,\ c}$		*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and for the constrained directional network element for constraint *c*, in the hour.

$\text{DAWASF}_{k,\,c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and for the constrained directional network element for constraint *c*, in the hour.
DASP_{c}	\$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price for the constraint *c* for the hour.
c	none	A constraint associated with a directional network element for the hour.

7.9.1.3 Minimum and Maximum Resource Prices

(1) For purposes of Section 7.9.1, Day-Ahead CRR Payments and Charges, Settlements data published to the Market Information System (MIS) Secure Area shall include the association of the Resource Category for each Generation Resource. The following prices specified in paragraphs (2) and (3) below are used in the CRR hedge value calculation for CRRs settled in the DAM.

> ***[NPRR1014: Replace paragraph (1) above with the following upon system implementation:]***
>
> (1) For purposes of Section 7.9.1, Day-Ahead CRR Payments and Charges, Settlements data published to the Market Information System (MIS) Secure Area shall include the association of the Resource Category for each Generation Resource and Energy Storage Resource (ESR). The following prices specified in paragraphs (2) and (3) below are used in the CRR hedge value calculation for CRRs settled in the DAM.

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

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

Where:

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

(a) Nuclear = -\$20.00/MWh;

(b) Hydro = -\$20.00/MWh;

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

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

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

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

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

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

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

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

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

(l) Wind = -$35/MWh;

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

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

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

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

(o) Other = -$20/MWh.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$MINRESPR_j$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for the Resources located at the source Settlement Point *j*.
$MINRESRPR_j$	$/MWh	*Minimum Resource Price for Resource*—The Minimum Resource Price for the Resources located at the source Settlement Point *j*.
r	none	A Generation Resource located at the source Settlement Point *j*. ***[NPRR1014: Replace the definition above with the following upon system implementation:]*** A Generation Resource or ESR located at the source Settlement Point *j*.
j	none	A source Settlement Point.

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

$$\mathbf{MAXRESPR}_{k} = \mathbf{Max\ (MAXRESRPR}_{k,\ r}\mathbf{)}_{r}$$

Where:

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

(a) Nuclear = $15.00/MWh;

(b) Hydro = \$10.00/MWh;

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

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

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

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

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

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

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

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

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

(l) Wind = \$0/MWh;

(m) PV = \$0/MWh;

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

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

(o) ESR = \$100/MWh; and

(o) Other = \$100/MWh.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
MAXRESPR_k	\$/MWh	*Maximum Resource Price for source*—The highest Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
MAXRESRPR_k	\$/MWh	*Maximum Resource Price for Resource*—The Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
r	none	A Generation Resource located at the sink Settlement Point *k*. ***[NPRR1014: Replace the definition above with the following upon system implementation:]*** A Generation Resource or ESR located at the sink Settlement Point *k*.
k	none	A sink Settlement Point.

7.9.1.4 Payments for FGRs Settled in DAM

There are currently no defined flowgates.

7.9.1.5 Payments and Charges for PTP Obligations with Refund Settled in DAM

(1) ERCOT shall pay the owner of a PTP Obligation with Refund the difference in the Day-Ahead Settlement Point Prices between the sink Settlement Point and the source Settlement Point, subject to a charge for refund, when the price difference is positive, as described in the item (1)(e)(i) of Section 7.4.2.2, PCRR Allocation and Nominations.

(2) The payment or charge to each CRR Owner for a given Operating Hour of PTP Obligations with Refund with each pair of source and sink Settlement Points settled in the DAM is calculated as follows:

$$\mathbf{DAOBLRAMT}_{o,\,(j,\,k)} = \mathbf{(-1) * DAOBLPR}_{(j,\,k)} \mathbf{* Min (DAOBLR}_{o,\,(j,\,k)}\mathbf{, OBLRACT}_{o,\,(j,\,k)}\mathbf{)}$$

Where:

$$\text{DAOBLPR}_{(j,\,k)} = \text{DASPP}_{k} - \text{DASPP}_{j}$$

$$\text{OBLRACT}_{o,\,(j,\,k)} = \sum_{r} (\text{OBLROF}_{o,\,r} * \text{RESACT}_{r} * \text{OBLRF}_{o,\,r,\,(j,\,k)})$$

If (a valid OS $_{r,\,y}$ exists for all Security-Constrained Economic Dispatch (SCED) intervals within the hour)

$$\text{RESACT}_{r} = \sum_{y} (\text{OS}_{r,\,y} * \text{TLMP}_{y}) \,/\, (\sum_{y} \text{TLMP}_{y})$$

Otherwise

$$\text{RESACT}_{r} = \text{TGFTH}_{r}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DAOBLRAMT $_{o,\,(j,\,k)}$	$	*Day-Ahead Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for the PTP Obligation with Refund with the source *j* and the sink *k*, settled in the DAM, for the hour.
DAOBLPR $_{(j,\,k)}$	$/MW per hour	*Day-Ahead Obligation Price*—The DAM price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
DASPP $_{j}$	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j* for the hour.
DASPP $_{k}$	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k* for the hour.
DAOBLR $_{o,\,(j,\,k)}$	MW	*Day-Ahead Obligation with Refund per CRR Owner per pair of source and sink*— The number of CRR Owner *o*'s PTP Obligations with Refund with the source *j* and the sink *k* settled in DAM for the hour.

Variable	**Unit**	**Definition**
OBLRACT $_{o,\ (j,\ k)}$	MW	*Obligation with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner *o*'s actual usage for the PTP Obligations with Refund with the source *j* and the sink *k*, for the hour.
RESACT $_{r}$	MW	*Resource Actual per Resource per hour*—The time-weighted average of the Output Schedule of Resource *r* (if a valid Output Schedule exists) or the telemetered output of Resource *r*, for the hour.
OBLROF $_{o,\ r}$	none	*Obligation with Refund Ownership Factor per CRR Owner per Resource*—The factor showing the percentage usage of Resource *r* for CRR Owner *o*'s PTP Obligations with Refund. Its value is 1, if only one CRR Owner has acquired Pre-Assigned Congestion Revenue Right (PCRRs) under the refund provision using this Resource *r*.
OS $_{r,\ y}$	MW	*Output Schedule per Resource per SCED interval*—The Output Schedule submitted to ERCOT for Resource *r* for the SCED interval *y*.
TGFTH $_{r}$	MWh	*Telemetered Generation for the Hour per Resource per hour*—The telemetered generation of Generation Resource *r*, for the hour.
OBLRF $_{o,\ r,\ (j,\ k)}$	none	*Obligation with Refund Factor per CRR Owner per Resource associated with pair of source and sink*—The ratio of CRR Owner *o*'s Resource *r*'s capacity allocated to the PTP Obligations with Refund with the source *j* and sink *k* to the same CRR Owner's total capacity for the Resource *r* nominated for all the PCRRs under the refund provision with the same source *j*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
o	none	A CRR Owner.
y	none	A SCED interval in the hour.
r	none	A Resource.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(3) The net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations with Refund settled in the DAM is calculated as follows:

$$\mathbf{DAOBLRAMTOTOT}_{\boldsymbol{o}} = \mathbf{DAOBLRCROTOT}_{\boldsymbol{o}} + \mathbf{DAOBLRCHOTOT}_{\boldsymbol{o}}$$

Where:

$$\text{DAOBLRCROTOT}_{o} = \sum_{j} \sum_{k} \text{Min}\ (0, \text{DAOBLRAMT}_{o,\ (j,\ k)})$$

$$\text{DAOBLRCHOTOT}_{o} = \sum_{j} \sum_{k} \text{Max}\ (0, \text{DAOBLRAMT}_{o,\ (j,\ k)})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DAOBLRAMTOTOT $_{o}$	$	*Day-Ahead Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* for all its PTP Obligations with Refund settled in the DAM, for the hour.

$DAOBLRCROTOT_{o}$	$	*Day-Ahead Obligation with Refund Credit Owner Total per CRR Owner*—The total payment to CRR Owner *o* for its PTP Obligations with Refund settled in the DAM, for the hour.
$DAOBLRCHOTOT_{o}$	$	*Day-Ahead Obligation with Refund Charge Owner Total per CRR Owner*—The total charge to CRR Owner *o* for its PTP Obligations with Refund settled in the DAM, for the hour.
$DAOBLRAMT_{o, (j, k)}$	$	*Day-Ahead Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for the PTP Obligations with Refund with the source *j* and the sink *k* settled in the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.1.6 Payments for PTP Options with Refund Settled in DAM

(1) ERCOT shall pay the owner of a PTP Option with Refund the difference in the DAM Settlement Point Prices between the sink Settlement Point and the source Settlement Point, if positive, subject to a charge for refund, as described in item (1)(e)(i) of Section 7.4.2.2, PCRR Allocation and Nominations.

(2) The payment to each CRR Owner for a given Operating Hour of its PTP Options with Refund with each pair of source and sink Settlement Points settled in the DAM is calculated as follows:

$$\mathbf{DAOPTRAMT}_{o, (j, k)} = \mathbf{(-1) * DAOPTPR}_{(j, k)} \mathbf{* Min (OPTR}_{o, (j, k)}\mathbf{, OPTRACT}_{o, (j, k)}\mathbf{)}$$

Where:

$$DAOPTPR_{(j, k)} = \text{Max}(0, DASPP_{k} - DASPP_{j})$$

$$OPTRACT_{o, (j, k)} = \sum_{r} (OPTROF_{o, r} * RESACT_{r} * OPTRF_{o, r, (j, k)})$$

If (a valid $OS_{r, y}$ exists for all SCED intervals within the hour)

$$RESACT_{r} = \sum_{y} (OS_{r, y} * TLMP_{y}) / (\sum_{y} TLMP_{y})$$

Otherwise

$$RESACT_{r} = TGFTH_{r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DAOPTRAMT_{o, (j, k)}$	$	*Day-Ahead Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for its PTP Options with Refund with the source *j* and the sink *k*, settled in the DAM, for the hour.
$DAOPTPR_{(j, k)}$	$/MW per hour	*Day-Ahead Option Price per pair of source and sink*—The DAM price of the PTP Option with the source *j* and the sink *k*, for the hour.

Variable	Unit	Definition
$DASPP_{j}$	\$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j*, for the hour.
$DASPP_{k}$	\$/MWh	*Day-Ahead Settlement Pont Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k*, for the hour.
$OPTR_{o, (j, k)}$	MW	*Option with Refund per CRR Owner per pair of source and sink*—The number of CRR Owner *o*'s PTP Options with Refund with the source *j* and the sink *k*, settled in DAM, for the hour.
$OPTRACT_{o, (j, k)}$	MW	*Option with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner *o*'s actual usage for the PTP Options with Refund with the source *j* and the sink *k*, for the hour.
$RESACT_{r}$	MW	*Resource Actual per Resource per hour*—The time-weighted average of the Output Schedule of Resource *r* (if a valid operating schedule exists) or the telemetered output of Resource *r*, for the hour.
$OPTROF_{o, r}$	none	*Option with Refund Ownership Factor per CRR Owner per Resource*—The factor showing the percentage usage of Resource *r* for CRR Owner *o*'s PTP Options with Refund. Its value is 1, if only one CRR Owner has acquired PCRRs under the refund provision using this Resource *r*.
$OS_{r, y}$	MW	*Output Schedule per Resource per SCED interval*—The Output Schedule submitted to ERCOT for Resource *r* for the SCED interval *y*.
$TGFTH_{r}$	MWh	*Telemetered Generation for the Hour per Resource per hour*—The telemetered generation of Generation Resource *r,* for the hour.
$OPTRF_{o, r, (j, k)}$	none	*Option with Refund Factor per CRR Owner per Resource associated with pair of source and sink*—The ratio of CRR Owner *o*'s Resource *r*'s capacity allocated to the PTP Options with Refund with the source *j* and sink *k* to the same CRR Owner's total capacity for the Resource *r* nominated PCRRs under the refund provision with the same source *j*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
o	none	A CRR Owner.
y	none	A SCED interval in the hour.
r	none	A Resource.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(3) The total payment to each Non-Opt-In-Entity (NOIE) CRR Owner for the Operating Hour of all its PTP Options with Refund settled in the DAM is calculated as follows:

$$\mathbf{DAOPTRAMTOTOT}_{o} = \sum_{j} \sum_{k} \mathbf{DAOPTRAMT}_{o, (j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DAOPTRAMTOTOT_{o}$	\$	*Day-Ahead Option with Refund Amount Owner Total per CRR Owner*—The total payment to NOIE CRR Owner *o* for all its PTP Options with Refund settled in the DAM, for the hour.
$DAOPTRAMT_{o, (j, k)}$	\$	*Day-Ahead Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to NOIE CRR Owner *o* for the PTP Options with Refund with the source *j* and the sink *k* settled in the DAM, for the hour.

Variable	Unit	Definition
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.2 Real-Time CRR Payments and Charges

7.9.2.1 Payments and Charges for PTP Obligations Settled in Real-Time

(1) ERCOT shall pay the Qualified Scheduling Entity (QSE) of each cleared PTP Obligation with links to an Option the positive difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment to each QSE for a given Operating Hour of its cleared PTP Obligation with links to an Option with each pair of source and sink Settlement Points is calculated as follows:

$$\textbf{RTOBLLOAMT}_{q,\,(j,\,k)} = \textbf{(-1) * MAX(0, RTOBLPR}_{(j,\,k)}\textbf{) * RTOBLLO}_{q,\,(j,\,k)}$$

(2) ERCOT shall pay or charge the QSE of each PTP Obligation acquired in the DAM the difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment or charge to each QSE for a given Operating Hour of its cleared PTP Obligations with each pair of source and sink Settlement Points is calculated as follows:

$$\textbf{RTOBLAMT}_{q,\,(j,\,k)} = \textbf{(-1) * RTOBLPR}_{(j,\,k)}\textbf{ * RTOBL}_{q,\,(j,\,k)}$$

(3) In the event that ERCOT is unable to execute the DAM, ERCOT shall pay or charge the owner of each PTP Obligation based on the difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment or charge to each CRR Owner for a given Operating Hour of its PTP Obligations with each pair of source and sink Settlement Points is calculated as follows:

$$\textbf{NDRTOBLAMT}_{o,\,(j,\,k)} = \textbf{(-1) * RTOBLPR}_{(j,\,k)}\textbf{ * DAOBL}_{o,\,(j,\,k)}$$

Where:

$$\text{RTOBLPR}_{(j,\,k)} = \sum_{i=1}^{4} (\text{RTSPP}_{k,\,i} - \text{RTSPP}_{j,\,i}) / 4$$

The above variables are defined as follows:

Variable	Unit	Definition
RTOBLAMT $_{q,\,(j,\,k)}$	\$	*Real-Time Obligation Amount per QSE per pair of source and sink*—The payment or charge to QSE q for its PTP Obligations with the source j and the sink k settled in Real-Time, for the hour.

Variable	Unit	Definition
$\text{RTOBLLOAMT}_{q, (j, k)}$	$	*Real-Time Obligation with Links to an Option Amount per QSE per pair of source and sink*—The payment to QSE *q* for its PTP Obligations with Links to an Option with the source *j* and the sink *k* settled in Real-Time, for the hour.
$\text{NDRTOBLAMT}_{o, (j, k)}$	$	*No DAM Real-Time Obligation Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for its PTP Obligations with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\text{RTOBLPR}_{(j, k)}$	$/MW per hour	*Real-Time Obligation Price*—The Real-Time price of the PTP Obligation, for the hour.
$\text{RTSPP}_{j, i}$	$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source *j* for the 15-minute Settlement Interval *i*.
$\text{RTSPP}_{k, i}$	$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink *k* for the 15-minute Settlement Interval *i*.
$\text{RTOBL}_{q, (j, k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
$\text{RTOBLLO}_{q, (j, k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids with Links to an Option cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
$\text{DAOBL}_{o, (j, k)}$	MW	*Day-Ahead Obligation per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM for the hour. See Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM.
o	none	A CRR Owner.
q	none	A QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(4) The net total payment or charge to each QSE for the Operating Hour of all its PTP Obligations settled in Real-Time is calculated as follows:

$$\mathbf{RTOBLAMTQSETOT}_{q} = \sum_{j} \sum_{k} \mathbf{RTOBLAMT}_{q, (j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RTOBLAMTQSETOT}_{q}$	$	*Real-Time Obligation Amount QSE Total per QSE*—The net total payment or charge to QSE *q* of all its PTP Obligations settled in Real-Time, for the hour.
$\text{RTOBLAMT}_{q, (j, k)}$	$	*Real-Time Obligation Amount per QSE per pair of source and sink*—The payment or charge to QSE *q* for the PTP Obligations with the source *j* and the sink *k* settled in Real-Time, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(5) The net total payment to each QSE for the Operating Hour of all its PTP Obligations with Links to Options settled in Real-Time is calculated as follows:

$$\textbf{RTOBLLOAMTQSETOT}_{q} = \sum_{j}\sum_{k}\textbf{RTOBLLOAMT}_{q,(j,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RTOBLLOAMTQSETOT}_{q}$	$	*Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The net total payment to QSE *q* of all its PTP Obligations with Links to an Option settled in Real-Time, for the hour.
$\text{RTOBLLOAMT}_{q,(j,k)}$	$	*Real-Time Obligation with Links to an Option Amount per QSE per pair of source and sink*—The payment to QSE *q* for the PTP Obligations with Links to an Option with the source *j* and the sink *k* settled in Real-Time, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(6) If ERCOT is unable to execute DAM, the net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations settled in Real-Time is calculated as follows:

$$\textbf{NDRTOBLAMTOTOT}_{o} = \sum_{j}\sum_{k}\textbf{NDRTOBLAMT}_{o,(j,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{NDRTOBLAMTOTOT}_{o}$	$	*No DAM Real-Time Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* of all its PTP Obligations settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\text{NDRTOBLAMT}_{o,(j,k)}$	$	*No DAM Real-Time Obligation Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for its PTP Obligations with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
o	None	A CRR Owner.
j	None	A source Settlement Point.
k	None	A sink Settlement Point.

7.9.2.2 Payments for PTP Options Settled in Real-Time

(1) When the DAM is not executed, ERCOT shall pay the owner of each PTP Option based on the positive difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment to each CRR Owner for a given Operating Hour of its PTP Options with each pair of source and sink Settlement Points is calculated as follows:

$$\textbf{NDRTOPTAMT}_{o,\,(j,\,k)} = (-1) * \textbf{NDRTOPTTP}_{o,\,(j,\,k)}$$

Where:

The target payment if ERCOT is unable to execute the DAM:

$$\text{NDRTOPTTP}_{o,\,(j,\,k)} = \text{RTOPTPR}_{(j,\,k)} * \text{OPT}_{o,\,(j,\,k)}$$

$$\text{RTOPTPR}_{(j,\,k)} = \sum_{i=1}^{4} \text{Max}\,(0, \text{RTSPP}_{k,\,i} - \text{RTSPP}_{j,\,i}) / 4$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
NDRTOPTAMT $_{o,\,(j,\,k)}$	$	*No DAM Real-Time Option Amount per CRR Owner per source and sink pair*—The payment to CRR Owner *o* of PTP Options with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTTP $_{o,\,(j,\,k)}$	$	*No DAM Real-Time Option Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
RTOPTPR $_{(j,\,k)}$	$/MW per hour	*Real-Time Option Price per source and sink pair*—The Real-Time price of a PTP Option or PTP Option with Refund with the source *j* and the sink *k* for the hour.
OPT $_{o,\,(j,\,k)}$	MW	*Option per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM for the hour. See Section 7.9.1.2, Payments for PTP Options Settled in DAM.
RTSPP $_{j,\,i}$	$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source Settlement Point *j*, for the 15-minute Settlement Interval *i*.
RTSPP $_{k,\,i}$	$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink Settlement Point *k*, for the 15-minute Settlement Interval *i*.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(2) If ERCOT is unable to execute the DAM, the total payment to each CRR Owner for the Operating Hour of all its PTP Options settled in Real-Time is calculated as follows:

$$\textbf{NDRTOPTAMTOTOT}_{o} = \sum_{j} \sum_{k} \textbf{NDRTOPTAMT}_{o,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
NDRTOPTAMTOTOT $_{o}$	$	*No DAM Real-Time Option Amount Owner Total per CRR Owner*—The total payment to CRR Owner *o* for all its PTP Options settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.

Variable	Unit	Definition
$NDRTOPTAMT_{o,\ (j,\ k)}$	$	*No DAM Real-Time Option Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for its PTP Options with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.2.3 Payments for NOIE PTP Options with Refund Settled in Real-Time

(1) When the DAM is not executed, ERCOT shall pay the NOIE owner of each PTP Option with Refund that was allocated to that NOIE as a PCRR, for the quantity up to the actual usage based on the positive difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment to each NOIE CRR Owner for a given Operating Hour of its PTP Options with Refund each pair of source and sink Settlement Points is calculated as follows:

$$\mathbf{NDRTOPTRAMT}_{o,\ (j,\ k)} = \mathbf{(-1) * NDRTOPTRTP}_{o,\ (j,\ k)}$$

Where:

The target payment if ERCOT is unable to execute the DAM:

$$NDRTOPTRTP_{o,\ (j,\ k)} = RTOPTPR_{(j,\ k)} * \text{Min}\ (OPTR_{o,\ (j,\ k)},\ OPTRACT_{o,\ (j,\ k)})$$

$$OPTRACT_{o,\ (j,\ k)} = \sum_{r} (OPTROF_{o,\ r} * RESACT_{r} * OPTRF_{o,\ r,\ (j,\ k)})$$

If (a valid $OS_{r,\ y}$ exists for all SCED intervals within the hour)

$$RESACT_{r} = \sum_{y} OS_{r,\ y} * TLMP_{y}) / (\sum_{y} TLMP_{y})$$

Otherwise

$$RESACT_{r} = TGFTH_{r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$NDRTOPTRAMT_{o,\ (j,\ k)}$	$	*No DAM Real-Time Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* of the PTP Options with Refund with the source *j* and the sink *k*, settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$NDRTOPTRAMT_{o,\ (j,\ k)}$	$	*No DAM Real-Time Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* of the PTP Options with Refund with the source *j* and the sink *k*, settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$NDRTOPTRTP_{o,\ (j,\ k)}$	$	*No DAM Real-Time Option with Refund Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner

Variable	**Unit**	**Definition**
		o's PTP Options with Refund, with the source j and the sink k, settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\text{RTSPP}_{j,\,i}$	\$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source j for the 15-minute Settlement Interval i.
$\text{RTSPP}_{k,\,i}$	\$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink k for the 15-minute Settlement Interval i.
$\text{RTOPTPR}_{(j,\,k)}$	\$/MW per hour	*Real-Time Option Price per source and sink pair*—The Real-Time price of a PTP Option with Refund with the source j and the sink k for the hour.
$\text{OPTRACT}_{o,\,(j,\,k)}$	MW	*Option with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner o's actual usage for the PTP Options with Refund with the source j and the sink k, for the hour.
RESACT_{r}	MW	*Resource Actual per Resource per hour*—The time-weighted average of the Output Schedule of Resource r (if a valid Output Schedule exists) or the telemetered output of Resource r, for the hour.
$\text{OPTROF}_{o,\,r}$	none	*Option with Refund Ownership Factor per CRR Owner per Resource*—The factor showing the percentage usage of Resource r for CRR Owner o's PTP Options with Refund. Its value is 1, if only one CRR Owner uses this Resource for PCRRs under the refund provision.
$\text{OS}_{r,\,y}$	MW	*Output Schedule per Resource per SCED interval*—The Output Schedule submitted to ERCOT for Resource r for the SCED interval y.
TGFTH_{r}	MWh	*Telemetered Generation for the Hour per Resource per hour*—The telemetered generation of Generation Resource r, for the hour.
$\text{OPTRF}_{o,\,r,\,(j,\,k)}$	none	*Option with Refund Factor per CRR Owner per Resource associated with pair of source and sink*—The ratio of CRR Owner o's Resource r's capacity allocated to the PTP Options with Refund with the source j and sink k to the same CRR Owner's total capacity for the Resource r nominated for all the PCRRs under the refund provision with the same source j.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval y within the hour.
$\text{OPTR}_{o,\,(j,\,k)}$	MW	*Option with Refund per CRR Owner per pair of source and sink*—The number of CRR Owner o's PTP Options with Refund settled in the DAM for the hour.
o	none	A CRR Owner.
r	none	A Resource.
y	none	A SCED interval in the hour.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(2) If ERCOT is unable to execute the DAM, the total payment to each NOIE CRR Owner for the Operating Hour of all its PTP Options with Refund settled in Real-Time is calculated as follows:

$$\textbf{NDRTOPTRAMTOTOT}_{o} = \sum_{j}\sum_{k} \textbf{NDRTOPTRAMT}_{o,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
NDRTOPTRAMTOTOT $_{o}$	$	*No DAM Real-Time Option with Refund Amount Owner Total per CRR Owner*—The total payment to NOIE CRR Owner *o* for all its PTP Options with Refund settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTRAMT $_{o,\,(j,\,k)}$	$	*No DAM Real-Time Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to NOIE CRR Owner *o* for the PTP Options with Refund with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.2.4 Payments for FGRs in Real-Time

(1) There are currently no defined flowgates.

7.9.2.5 Payments and Charges for PTP Obligations with Refund in Real-Time

(1) In the event that ERCOT is unable to execute the DAM, ERCOT shall pay or charge the NOIE owner of a PTP Obligation with Refund, for the quantity up to the actual usage based on the difference in the Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment or charge to each NOIE CRR Owner for a given Operating Hour of its PTP Options with Refund each pair of source and sink Settlement Points in Real-Time is calculated as follows:

$$\textbf{NDRTOBLRAMT}_{o,\,(j,\,k)} = \textbf{(-1) * NDRTOBLRTP}_{o,\,(j,\,k)}$$

Where:

The target payment:

$$\text{NDRTOBLRTP}_{o,\,(j,\,k)} = \text{RTOBLRPR}_{(j,\,k)} * \text{Min}\ (\text{DAOBLR}_{o,\,(j,\,k)},\ \text{OBLRACT}_{o,\,(j,\,k)})$$

$$\text{RTOBLPR}_{(j,\,k)} = \sum_{i=1}^{4} (\text{RTSPP}_{k,\,i} - \text{RTSPP}_{j,\,i}) / 4$$

$$\text{OBLRACT}_{o,\,(j,\,k)} = \sum_{r} (\text{OBLROF}_{o,\,r} * \text{RESACT}_{r} * \text{OBLRF}_{o,\,r,\,(j,\,k)})$$

If (a valid OS $_{r,\,y}$ exists for all SCED intervals within the hour)

$$\text{RESACT}_{r} = \sum_{y} (\text{OS}_{r,\,y} * \text{TLMP}_{y}) \,/\, (\sum_{y} \text{TLMP}_{y})$$

Otherwise

$$\text{RESACT}_{r} = \text{TGFTH}_{r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{NDRTOBLRAMT}_{o,\,(j,\,k)}$	$	*No DAM Real-Time Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for the PTP Obligation with Refund with the source *j* and the sink *k*, settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
$\text{NDRTOBLRTP}_{o,\,(j,\,k)}$	$	*No DAM Real-Time Obligation with Refund Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Obligations with Refund, with the source *j* and the sink *k*, settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
$\text{RTOBLPR}_{(j,\,k)}$	$/MW per hour	*Real-Time Obligation Price*—The Real-Time price of the PTP Obligation, for the hour.
$\text{RTSPP}_{j,\,i}$	$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source *j* for the 15-minute Settlement Interval *i*.
$\text{RTSPP}_{k,\,i}$	$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink *k* for the 15-minute Settlement Interval *i*.
$\text{DAOBLR}_{o,\,(j,\,k)}$	MW	*Day-Ahead Obligation with Refund per CRR Owner per pair of source and sink*—The number of CRR Owner *o*'s PTP Obligations with Refund with the source *j* and the sink *k* settled in DAM for the hour. See Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM.
$\text{OBLRACT}_{o,\,(j,\,k)}$	MW	*Obligation with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner *o*'s actual usage for the PTP Obligations with Refund with the source *j* and the sink *k*, for the hour.
RESACT_{r}	MW	*Resource Actual per Resource per hour*—The time-weighted average of the Output Schedule of Resource *r* (if a valid Output Schedule exists) or the telemetered output of Resource *r*, for the hour.
$\text{OBLROF}_{o,\,r}$	none	*Obligation with Refund Ownership Factor per CRR Owner per Resource*—The factor showing the percentage usage of Resource *r* for CRR Owner *o*'s PTP Obligations. Its value is 1, if only one CRR Owner has acquired PCRRs under the refund provision using this Resource *r*.
$\text{OS}_{r,\,y}$	MW	*Output Schedule per Resource per SCED interval*—The Output Schedule submitted to ERCOT for Resource *r* for the SCED interval *y*.
TGFTH_{r}	MWh	*Telemetered Generation for the Hour per Resource per Hour*—The telemetered generation of Generation Resource *r*, for the hour.
$\text{OBLRF}_{o,\,r,\,(j,\,k)}$	none	*Obligation with Refund Factor per CRR Owner per Resource*—The ratio of CRR Owner *o*'s Resource *r*'s capacity allocated to the PTP Obligations with Refund with the source *j* and sink *k* to the same CRR Owner's total capacity for the Resource *r* nominated for all the PCRRs under the refund provision with the same source *j*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
o	none	A CRR Owner.
y	none	A SCED interval in the hour.

Variable	Unit	Definition
r	none	A Resource.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(2) If ERCOT is unable to execute the DAM, the net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations with Refund settled in Real-Time is calculated as follows:

$$\text{NDRTOBLRAMTOTOT}_{o} = \sum_{j} \sum_{k} \text{NDRTOBLRAMT}_{o,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{NDRTOBLRAMTOTOT}_{o}$	$	*No DAM Real-Time Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* for all its PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
$\text{NDRTOBLRAMT}_{o,\,(j,\,k)}$	$	*No DAM Real-Time Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for the PTP Obligation with Refund with the source *j* and the sink *k*, settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.3 CRR Balancing Account

7.9.3.1 DAM Congestion Rent

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

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

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

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

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

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

$$\mathbf{DACONGRENT = DAESAMTTOT + DAEPAMTTOT + DARTOBLAMTTOT + DARTOBLLOAMTTOT}$$

Where:

$$\text{DAESAMTTOT} = \sum_{q} \text{DAESAMTQSETOT}_{q}$$

$$\text{DAEPAMTTOT} = \sum_{q} \text{DAEPAMTQSETOT}_{q}$$

$$\text{DARTOBLAMTTOT} = \sum_{q} \text{DARTOBLAMTQSETOT}_{q}$$

$$\text{DARTOBLLOAMTTOT} = \sum_{q} \text{DARTOBLLOAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DACONGRENT	$	*Day-Ahead Congestion Rent*—The congestion rent collected in the DAM for the hour.
DAESAMTTOT	$	*Day-Ahead Energy Sale Amount Total*—The total payment to all QSEs for cleared DAM energy offers, whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves for the hour.
DAEPAMTTOT	$	*Day-Ahead Energy Purchase Amount Total*—The total charge to all QSEs for cleared DAM Energy Bids for the hour.
DARTOBLAMTTOT	$	*Day-Ahead Real-Time Obligation Amount Total*—The net total charge or payment to all QSEs for cleared PTP Obligation bids in the DAM for the hour.
DARTOBLLOAMTTOT	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount Total*—The net total charge to all QSEs for charge to QSE *q* for a PTP Obligation with Links to an Option Bid cleared in the DAM with the source *j* and the sink *k*, for the hour.
DAESAMTQSETOT_{q}	$	*Day-Ahead Energy Sale Amount QSE Total per QSE*—The total payment to QSE *q* for cleared DAM energy offers, whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves, for the hour. See item (2) of Section 4.6.2.1.
DAEPAMTQSETOT_{q}	$	*Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total charge to QSE *q* for cleared DAM Energy Bids for the hour. See item (2) of Section 4.6.2.2.
$\text{DARTOBLAMTQSETOT}_{q}$	$	*Day-Ahead Real-Time Obligation Amount QSE Total per QSE*—The total charge or payment to QSE *q* for PTP Obligation Bids cleared in the DAM for the hour. See item (2) of Section 4.6.3.
$\text{DARTOBLLOAMTQSETOT}_{q}$	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The net total charge to QSE q for all its PTP Obligation with Links to an Option Bids cleared in the DAM for the hour.
q	none	A QSE.

7.9.3.2 Credit to CRR Balancing Account

(1) If the Day-Ahead Congestion Rent is greater than the total payment to all CRR Owners for the CRRs settled in the DAM for any Operating Hour, a credit is put into the CRR Balancing Account for that Operating Hour. The credit to the CRR Balancing Account for a given Operating Hour is calculated as follows:

$$\mathbf{CRRBACR = Max\ (0, (DACONGRENT + DACRRCRTOT + DACRRCHTOT))}$$

Where:

$$\text{DACRRCRTOT} = \text{DAOBLCRTOT} + \text{DAOBLRCRTOT} + \text{DAOPTAMTTOT} + \text{DAOPTRAMTTOT}$$

$$\text{DACRRCHTOT} = \text{DAOBLCHTOT} + \text{DAOBLRCHTOT}$$

$$\text{DAOBLCRTOT} = \sum_{o} \text{DAOBLCROTOT}_{o}$$

$$\text{DAOBLCHTOT} = \sum_{o} \text{DAOBLCHOTOT}_{o}$$

$$\text{DAOBLRCRTOT} = \sum_{o} \text{DAOBLRCROTOT}_{o}$$

$$\text{DAOBLRCHTOT} = \sum_{o} \text{DAOBLRCHOTOT}_{o}$$

$$\text{DAOPTAMTTOT} = \sum_{o} \text{DAOPTAMTOTOT}_{o}$$

$$\text{DAOPTRAMTTOT} = \sum_{o} \text{DAOPTRAMTOTOT}_{o}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
CRRBACR	$	*CRR Balancing Account Credit*—The credit to the CRR Balancing Account for the hour.
DACONGRENT	$	*Day-Ahead Congestion Rent*—The congestion rent collected in the DAM for the hour. See Section 7.9.3.1, DAM Congestion Rent.
DACRRCRTOT	$	*Day-Ahead CRR Credit Total*—The total payment to all CRR Owners of all CRRs settled in the DAM, for the hour.
DACRRCHTOT	$	*Day-Ahead CRR Charge Total*—The total charge to all CRR Owners of all CRRs settled in the DAM, for the hour.
DAOBLCRTOT	$	*Day-Ahead Obligation Credit Total*—The total payment of all PTP Obligations settled in the DAM, for the hour.
DAOBLCHTOT	$	*Day-Ahead Obligation Charge Total*—The total charge of all PTP Obligations settled in the DAM, for the hour.
DAOBLRCRTOT	$	*Day-Ahead Obligation with Refund Credit Total*—The total payment of all PTP Obligations with Refund settled in the DAM, for the hour.

Variable	Unit	Definition
DAOBLRCHTOT	$	*Day-Ahead Obligation with Refund Charge Total*—The total charge of all PTP Obligations with Refund settled in the DAM, for the hour.
DAOPTAMTTOT	$	*Day-Ahead Option Amount Total*—The total payment of all PTP Options settled in the DAM, for the hour.
DAOPTRAMTTOT	$	*Day-Ahead Option with Refund Amount Total*—The total payment of all PTP Options with Refund settled in the DAM, for the hour.
DAOBLCROTOT_{o}	$	*Day-Ahead Obligation Credit Owner Total per owner*—The total payment to CRR Owner *o* of PTP Obligations settled in the DAM, for the hour. See Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM.
DAOBLCHOTOT_{o}	$	*Day-Ahead Obligation Charge Owner Total per owner*—The total charge to CRR Owner *o* of PTP Obligations settled in the DAM, for the hour. See Section 7.9.1.1.
DAOBLRCROTOT_{o}	$	*Day-Ahead Obligation with Refund Credit Owner Total per owner*—The total payment to the CRR Owner *o* of PTP Obligations with Refund settled in the DAM, for the hour. See Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM.
DAOBLRCHOTOT_{o}	$	*Day-Ahead Obligation with Refund Charge Owner Total per owner*—The total charge to CRR Owner *o* of PTP Obligations with Refund settled in the DAM, for the hour. See Section 7.9.1.5.
DAOPTAMTOTOT_{o}	$	*Day-Ahead Option Amount Owner Total per owner*—The total payment to the CRR Owner *o* of PTP Options settled in the DAM, for the hour. See Section 7.9.1.2, Payments for PTP Options Settled in DAM.
DAOPTRAMTOTOT_{o}	$	*Day-Ahead Option with Refund Amount Owner Total per owner*—The total payment to the CRR Owner *o* of PTP Options with Refund settled in the DAM, for the hour. See Section 7.9.1.6, Payments for PTP Options with Refund Settled in DAM.
o	none	A CRR Owner.

7.9.3.3 Shortfall Charges to CRR Owners

(1) For each Operating Hour, if the Day-Ahead Congestion Rent is less than the total payment to all CRR Owners for the CRRs settled in the DAM, a charge will be made to each CRR Owner for any of its CRRs settled in the DAM that have positive Settlement prices.

(2) The charge to each CRR Owner for its CRRs settled in the DAM for a given Operating Hour is calculated as follows:

$$\textbf{DACRRSAMT}_{o} = \textbf{DACRRSAMTTOT * CRRCRRSDA}_{o}$$

Where:

$$\textbf{DACRRSAMTTOT} = \textbf{(-1) * Min (0, DACONGRENT + DACRRCRTOT + DACRRCHTOT)}$$

$$\text{CRRCRRSDA}_{o} = (\text{DAOBLCROTOT}_{o} + \text{DAOBLRCROTOT}_{o} + \text{DAOPTAMTOTOT}_{o} + \text{DAOPTRAMTOTOT}_{o}) / (\text{DACRRCRTOT})$$

The above variables are defined as follows:

Variable	Unit	Definition
DACRRSAMT_{o}	$	*Day-Ahead CRR Shortfall Amount per owner*—The shortfall charge to CRR Owner *o* for its CRRs settled in the DAM, for the hour.
DACRRSAMTTOT	$	*Day-Ahead CRR Shortfall Amount Total*—The shortfall charge to all CRR Owners for their CRRs settled in the DAM and the Real-Time Market (RTM), for the hour.
DACONGRENT	$	*Day-Ahead Congestion Rent*—The Congestion Rent collected in the DAM for the hour. See Section 7.9.3.1, DAM Congestion Rent.
DACRRCRTOT	$	*Day-Ahead CRR Credit Total*—The total payment to all CRR Owners of all the CRRs settled in the DAM, for the hour. See Section 7.9.3.2, Credit to CRR Balancing Account.
DACRRCHTOT	$	*Day-Ahead CRR Charge Total*—The total charge to all CRR Owners of all the CRRs settled in the DAM, for the hour. See Section 7.9.3.2.
CRRCRRSDA_{o}	none	*CRR Credit Ratio Share Day-Ahead per owner*—The ratio of the total payments to CRR Owner *o* of its CRRs settled in the DAM to the total payments to all CRR Owners of all CRRS, for the hour.
DAOBLCROTOT_{o}	$	*Day-Ahead Obligation Credit Owner Total per owner*—The total payment to CRR Owner *o* of PTP Obligations settled in the DAM, for the hour. See Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM.
DAOBLRCROTOT_{o}	$	*Day-Ahead Obligation with Refund Credit Owner Total per owner*—The total payment to CRR Owner *o* of PTP Obligations with Refund settled in the DAM, for the hour. See Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM.
DAOPTAMTOTOT_{o}	$	*Day-Ahead Option Amount Owner Total per owner*—The total payment to CRR Owner *o* of PTP Options settled in the DAM, for the hour. See Section 7.9.1.2, Payments PTP Options Settled in DAM.
DAOPTRAMTOTOT_{o}	$	*Day-Ahead Option with Refund Amount Owner Total per owner*—The total payment to CRR Owner *o* of PTP Options with Refund settled in the DAM, for the hour. See Section 7.9.1.6, Payments for PTP Options with Refund Settled in DAM.
o	none	A CRR Owner.

7.9.3.4 Monthly Refunds to Short-Paid CRR Owners

(1) On a monthly basis, a refund may be paid to the CRR Owners that have a shortfall charge for any Operating Hour in a month. The refund to each CRR Owner for a given month is calculated as follows:

If CRRBACRTOT + CRRFEETOT < CRRSAMTTOT :

$$\mathbf{CRRRAMT}_{o} = (-1) * \text{Min}(\text{CRRBACRTOT} + \text{CRRFEETOT} + \text{CRRBAFA}_{m}, \text{CRRSAMTTOT}) * \text{CRRSAMTRS}_{o}$$

Where:

$$\text{CRRBAFA}_{m} = \text{Min (CRRBAFBBAL, CRRSAMTTOT} - \text{(CRRBACRTOT + CRRFEETOT))}$$

Otherwise:

$$\text{CRRRAMT}_{o} = (-1) * \text{Min (CRRBACRTOT + CRRFEETOT, CRRSAMTTOT)} * \text{CRRSAMTRS}_{o}$$

Where:

$$\text{CRRBACRTOT} = \sum_{h} \text{CRRBACR}_{h}$$

$$\text{CRRFEETOT} = \sum_{crrh} \sum_{a} (\text{OPTAFAMT}_{crrh,\ a})$$

If (CRRSAMTTOT = 0)

$$\text{CRRSAMTRS}_{o} = 0$$

Otherwise:

$$\text{CRRSAMTRS}_{o} = \text{CRRSAMTOTOT}_{o} / \text{CRRSAMTTOT}$$

$$\text{CRRSAMTTOT} = \sum_{o} \text{CRRSAMTOTOT}_{o}$$

$$\text{CRRSAMTOTOT}_{o} = \sum_{h} \text{DACRRSAMT}_{o,\ h}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
CRRRAMT_{o}	$	*CRR Refund Amount per owner*—The refund to the short-paid CRR Owner *o* for the month.
CRRBACRTOT	$	*CRR Balancing Account Credit Total*—The total of credits accumulated in the CRR Balancing Account for all Operating Hours in the month.
CRRBAFA_{m}	$	*CRR Balancing Account Fund Available*—The amount available to cover CRR shortfalls from the CRR Balancing Account fund for the month.
CRRBAFBBAL	$	*CRR Balancing Account Fund Beginning Balance*—The amount in the CRR Balancing Account Fund at the previous Settlement.
CRRSAMTTOT	$	*CRR Shortfall Amount Total*—The total of shortfall charges to all CRR Owners for all Operating Hours in the month.
CRRSAMTRS_{o}	none	*CRR Shortfall Amount Ratio Share per owner*—The ratio of the CRR Owner *o*'s total shortfall-charge to the total of all the CRR Owners' shortfall charges, for the month.
CRRSAMTOTOT_{o}	$	*CRR Shortfall Amount Owner Total per owner*—The total of shortfall charges to CRR Owner *o* for all Operating Hours in the month.

Variable	Unit	Definition
$\text{DACRRSAMT}_{o,\,h}$	$	*Day-Ahead CRR Shortfall Amount per owner per hour*—The shortfall charge to CRR Owner *o* for its CRRs settled in the DAM for the hour *h*.
CRRBACR_{h}	$	*CRR Balancing Account Credit per hour*—The credit to the CRR Balancing Account for the hour *h*.
CRRFEETOT	$	*CRR Auction PTP Option Award Charge Total*—The sum of the PTP Option Award Charges to all CRR Account Holders in single-month or multi-month CRR Auctions for the month.
$\text{OPTAFAMT}_{crrh,\,a}$	$	*PTP Option Award Charge Amount per CRR Account Holder per CRR Auction*—The charge assessed to CRR Account Holder *crrh* for PTP Option awards awarded in CRR Auction *a*, for the hour for which the clearing price is less than the defined Minimum PTP Option Bid Price for the month. For a multi-month CRR Auction, the charge shall be calculated for each month.
m	none	A month.
h	none	An Operating Hour in the month.
o	none	A CRR Owner.
crrh	none	A CRR Account Holder.
a	none	A CRR Auction

7.9.3.5 CRR Balancing Account Closure

(1) After the calculation of refunds described in Section 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners, any CRR Balancing Account and CRR Auction PTP Option Award Charge Total in excess of the refunds described in Section 7.9.3.4 will first be used to fund the CRR Balancing Account Fund if the prior month's CRR Balancing Account Fund Balance is less than the CRR Balancing Account Fund Cap. Any surplus that remains from the CRR Balancing Account and CRR Auction PTP Option Award Charge Total above the CRR Balancing Account Fund cap is paid to the QSEs representing Load Serving Entities (LSEs) based on a monthly Load Ratio Share (LRS). The monthly LRS is the 15-minute LRS calculated for the peak-Load Settlement Interval during the month. The CRR Balancing Account Fund Cap is $10 million.

[NPRR1030: Replace paragraph (1) above with the following upon system implementation:]

(1) After the calculation of refunds described in Section 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners, any CRR Balancing Account and CRR Auction PTP Option Award Charge Total in excess of the refunds described in Section 7.9.3.4 will first be used to fund the CRR Balancing Account Fund if the prior month's CRR Balancing Account Fund Balance is less than the CRR Balancing Account Fund Cap. Any surplus that remains from the CRR Balancing Account and CRR Auction PTP Option Award Charge Total above the CRR Balancing Account Fund cap is paid to the QSEs representing Load Serving Entities (LSEs) based on the QSEs ratio shares. The CRR Balancing Account Fund Cap is $10 million.

(2) The credit to each QSE representing LSEs for a given month is calculated as follows:

$$\mathbf{LACRRAMT}_q = (-1) * \text{Max}((\text{CRRBACRTOT} + \text{CRRFEETOT} + \text{CRRRAMTTOT}) - (\text{FUNDCAP} - \text{CRRBAFBBAL}), 0) * \text{MLRS}_q$$

Where:

$$\text{CRRRAMTTOT} = \sum_{o} \text{CRRRAMT}_o$$

The above variables are defined as follows:

Variable	Unit	Definition
LACRRAMT_q	$	*Load-Allocated CRR Amount per QSE*—The allocated surplus from the CRR Balancing Account and CRR Auction PTP Option Award Charge Total at the end of the month to QSE *q*, based on LRS for the month.
CRRBAFBBAL	$	*CRR Balancing Account Fund Beginning Balance*—The amount in the CRR Balancing Account Fund at the end of the previous month.
FUNDCAP	$	*CRR Balancing Account Fund Cap*—The threshold amount in the CRR Balancing Account Fund above which funds are available to allocate to QSEs representing Load.
CRRBACRTOT	$	*CRR Balancing Account Credit Total*—The total credit accumulated in the CRR Balancing Account during the month. See its calculation in Section 7.9.3.4.
CRRFEETOT	$	*CRR Auction PTP Option Award Charge Total*—The sum of the PTP Option Award Charges to all CRR Account Holders in single-month or multi-month CRR Auctions for the month.
CRRRAMTTOT	$	*CRR Refund Amount Total*—The total refund to all the previously short-paid CRR Owners at the end of the month.
CRRRAMT_o	$	*CRR Refund Amount per owner*—The refund credited to the CRR Owner *o* at the end of the month.
MLRS_q	none	*Monthly Load Ratio Share per QSE*—The LRS calculated for QSE *q* for the 15-minute monthly peak-load Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval, for the calculation of LRS for a 15-minute Settlement Interval.
m	none	A month.
q	none	A QSE.
o	none	A CRR Owner.

[NPRR1030 and NPRR1054: Replace applicable portions of paragraph (2) above with the following upon system implementation:]

(2) The credit to each QSE representing LSEs for a given month is calculated as follows:

$$\mathbf{LACRRAMT}_q = (-1) * (\text{CRRDC}_q + \text{CRRNDC}_q)$$

Where:

$$\text{CRRNDC}_q = (\text{CRRALLOCTOT} - \sum_{q} \text{CRRDC}_q) * \text{MLRS}_q$$

$$\text{CRRDC}_q = \text{CRRALLOCTOT} * \text{DCMLRS}_q$$

$$\text{CRRALLOCTOT} = \text{Max}((\text{CRRBACRTOT} + \text{CRRFEETOT} + \text{CRRRAMTTOT}) - (\text{FUNDCAP} - \text{CRRBAFBBAL}), 0)$$

$$\text{CRRRAMTTOT} = \sum_{o} \text{CRRRAMT}_{o}$$

The above variables are defined as follows:

Variable	Unit	Definition
LACRRAMT $_{q}$	$	*Load-Allocated CRR Amount per QSE*—The allocated surplus from the CRR Balancing Account and CRR Auction PTP Option Award Charge Total at the end of the month to QSE *q* with Loads and Direct Current Tie (DC Tie) exports.
CRRDC $_{q}$	$	*CRR Amount for DC Tie Exports per QSE*—The allocated surplus from the CRR Balancing Account and CRR Auction PTP Option Award Charge Total at the end of the month to QSE *q* for DC Tie Exports based on DC Tie ratio shares for the month.
CRRNDC $_{q}$	$	*CRR Amount for Non-DC Tie Loads per QSE*—The allocated surplus from the CRR Balancing Account and CRR Auction PTP Option Award Charge Total at the end of the month to QSE *q* for Load (excluding DC Tie exports), based on ratio share for the peak Load 15-minute Settlement Interval for the month.
CRRBAFBBAL	$	*CRR Balancing Account Fund Beginning Balance*—The amount in the CRR Balancing Account Fund at the end of the previous month.
FUNDCAP	$	*CRR Balancing Account Fund Cap*—The threshold amount in the CRR Balancing Account Fund above which funds are available to allocate to QSEs representing Load.
CRRBACRTOT	$	*CRR Balancing Account Credit Total*—The total credit accumulated in the CRR Balancing Account during the month. See its calculation in Section 7.9.3.4.
CRRFEETOT	$	*CRR Auction PTP Option Award Charge Total*—The sum of the PTP Option Award Charges to all CRR Account Holders in single-month or multi-month CRR Auctions for the month.
CRRALLOCTOT	$	*CRR Allocation Amount Total* – The surplus from the CRR Balancing Account and CRR Auction PTP Option Award Charge Total at the end of the month.
CRRRAMTTOT	$	*CRR Refund Amount Total*—The total refund to all the previously short-paid CRR Owners at the end of the month.
CRRRAMT $_{o}$	$	*CRR Refund Amount per owner*—The refund credited to the CRR Owner *o* at the end of the month.
DCMLRS $_{q}$	none	*DC Tie Monthly Load Ratio Share per QSE*—The ratio share calculated for QSE *q* with DC Tie exports for the calendar month. See Section 6.6.2.6, QSE DC Tie Export Load Ratio Share for a Month.
MLRS $_{q}$	none	*Monthly Load Ratio Share per QSE* — The ratio share of Loads excluding DC Tie exports for QSE *q*, for the peak Load 15-minute Settlement Interval in the month.
q	none	A QSE.
o	none	A CRR Owner.

7.9.3.6 Rolling CRR Balancing Account Fund

(1) ERCOT shall establish a rolling CRR Balancing Account Fund (CRRBAF) as follows:

(a) The CRRBAF shall be funded beginning in the first month after implementation and every month that the CRR Balancing Account credit exceeds monthly CRR shortfalls.

(b) The CRRBAF calculated for a month shall not exceed the CRR Balancing Account Fund Cap.

(c) The CRRBAF shall refund to LSEs any surplus above the fund cap.

(d) In the event that a resettlement of the CRR Balancing Account is required, the CRRBAF for the resettlement will be calculated using the CRRBAF at the end of the previous month from the date of the resettlement invoice.

(e) The end of the month CRRBAF is calculated as follows:

If CRRBACRTOT + CRRFEETOT < CRRSAMTTOT:

$$\mathbf{CRRBAF}_{\boldsymbol{m}} = \mathbf{CRRBAFBBAL - CRRBAFA}_{\boldsymbol{m}}$$

Otherwise if CRRBACRTOT + CRRFEETOT > CRRSAMTTOT and CRRBAF < FUNDCAP:

$$\mathbf{CRRBAF}_{\boldsymbol{m}} = \mathbf{CRRBAFBBAL + (CRRBACRTOT + CRRFEETOT - CRRSAMTTOT) + LACRRAMTTOT}$$

Where:

$$\text{LACRRAMTTOT} = \sum_{q} \text{LACRRAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
CRRBACRTOT	$	*CRR Balancing Account Credit Total*—The total credit accumulated in the CRR Balancing Account during the month. See its calculation in Section 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners.
CRRFEETOT	$	*CRR Auction Fee Total*—The sum of the PTP Option Award Fees charged to all CRR Account Holders in single-month or multi-month CRR Auctions for the month.
CRRSAMTTOT	$	*CRR Shortfall Amount Total*—The total of shortfall charges to all CRR Owners for all Operating Hours in the month.
CRRBAFBBAL	$	*CRR Balancing Account Fund Beginning Balance*—The amount in the CRR Balancing Account Fund at the end of the previous month.
CRRBAF_m	$	*CRR Balancing Account Fund Balance*—The amount in the CRR Balancing Account Fund at the end of the current month.
CRRBAFA_m	$	*CRR Balancing Account Fund Available*—The amount available to cover CRR shortfalls from the CRR Balancing Account Fund for the month.
FUNDCAP	$	*CRR Balancing Account Fund Cap*—The threshold amount in the CRR Balancing Account Fund above which funds are available to allocate to QSEs representing Load.

Variable	**Unit**	**Definition**
LACRRAMTTOT	$	*Load-Allocated CRR Amount Total*—The net total surplus from the CRR Balancing Account and CRR Auction fees at the end of the month.
LACRRAMT $_q$	$	*Load-Allocated CRR Amount per QSE*—The allocated surplus from the CRR Balancing Account and CRR Auction fees at the end of the month to QSE *q*, based on LRS for the month.
m	none	A month.

ERCOT Nodal Protocols

Section 8: Performance Monitoring

December 9, 2022

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8 Performance Monitoring

8 PERFORMANCE MONITORING

(1) This Section describes how the performance of ERCOT, Transmission Service Providers (TSPs) and Qualified Scheduling Entities (QSEs) are measured against the requirements of these Protocols. All performance measures must be approved by the Technical Advisory Committee (TAC) prior to implementation. Summaries of the performance of each TSP and QSE and of ERCOT are to be made available on the Market Information System (MIS) Secure Area unless otherwise stated.

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) This Section describes how the performance of ERCOT, Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), and Qualified Scheduling Entities (QSEs) are measured against the requirements of these Protocols. All performance measures must be approved by the Technical Advisory Committee (TAC) prior to implementation. Summaries of the performance of each TSP, DCTO, and QSE and of ERCOT are to be made available on the Market Information System (MIS) Secure Area unless otherwise stated.

8.1 QSE and Resource Performance Monitoring

(1) ERCOT shall develop a Technical Advisory Committee (TAC)- and ERCOT Board-approved Qualified Scheduling Entity (QSE) and Resource monitoring program to be included in the Operating Guides. Nothing in this Section changes the process for amending the Operating Guides. The metrics developed by ERCOT and approved by TAC and the ERCOT Board must include the provisions of this Section.

(2) Each QSE and Resource shall meet performance measures as described in this Section and in the Operating Guides.

(3) ERCOT shall monitor and post the following categories of performance:

(a) Real-Time data, for QSEs:

(i) Telemetry performance

(b) Regulation control performance, for QSEs and as applicable, Resource-specific performance (see also Section 8.1.1, QSE Ancillary Service Performance Standards);

(c) Hydro responsive testing for Generation Resources;

(d) Supplying and validating data for generator models, as requested by ERCOT, for Generation Resources;

(e) Outage scheduling and coordination, for QSEs and Resources;

(f) Resource-specific Responsive Reserve (RRS) performance for QSEs and Resources;

(g) Resource-specific Non-Spinning Reserve (Non-Spin) performance, for QSEs and Resources;

[NPRR863: Insert paragraph (h) below upon system implementation and renumber accordingly:]

> (h) Resource-specific ERCOT Contingency Reserve Service (ECRS) performance for QSEs and Resources;

(h) Outage reporting, by QSEs for Resources;

(i) Current Operating Plan (COP) metrics, for QSEs; and

(j) Day-Ahead Reliability Unit Commitment (DRUC) and Hourly Reliability Unit Commitment (HRUC) commitment performance by QSEs and Generation Resources.

8.1.1 QSE Ancillary Service Performance Standards

(1) Each QSE and its Resources that provide Ancillary Service must meet performance measures set out in these Protocols and the Operating Guides. ERCOT shall develop a TAC- and ERCOT Board-approved Ancillary Service monitoring program to evaluate the performance of QSEs and Resources providing Ancillary Services prior to the Texas Nodal Market Implementation Date. This program must include monitoring of capacity availability and energy deployments as described below and in Section 6.5.7.5, Ancillary Services Capacity Monitor.

8.1.1.1 Ancillary Service Qualification and Testing

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

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

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

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

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

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

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

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

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

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

(a) The Resource's Responsibility for RRS, or

(b) The requested MW deployment.

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

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

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

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

(b) The MW deployment.

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

FFR test, in any rolling 365-day period, it is subject to an FFR test by ERCOT. All performance evaluations will apply on an individual Resource basis.

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

[NPRR863, NPRR963, and NPRR1011: Replace applicable portions of Section 8.1.1.1 above with the following upon system implementation for NPRR863 or NPRR963; or upon system implementation of Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.1 Ancillary Service Qualification and Testing

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

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

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

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

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

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

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

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

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

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

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

(b) The requested MW deployment.

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

(9) ERCOT may revoke the Ancillary Service qualification of any Load Resource, excluding Controllable Load Resources, for failure to comply with the required

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

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

(a) The Resource's RRS award; or

(b) The MW deployment.

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

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

8.1.1.2 General Capacity Testing Requirements

(1) Within the first 15 days of each Season, each QSE shall provide ERCOT a Seasonal HSL for any Generation Resource with a capacity greater than ten MW that will be operated during that Season. ERCOT shall provide an appropriate form for QSEs to submit their Seasonal HSL data. The Seasonal HSL form shall take into account auxiliary Load and gross and net real power capability of the Generation Resource. Each QSE shall update its COP and telemetry, as necessary, to reflect the HSL of each of its Generation Resources in a given operating interval as well as other operational limitations. The HSL shown in the COP for a Generation Resource may not be ramp rate-limited while the Real-Time telemetered value of HSL for the Generation Resource may be ramp rate-limited by the QSE representing the Generation Resource in order for the Generation Resource to meet its HSL using the testing process described in paragraph (2) below.

(2) To verify that the HSL reported by telemetry is achievable, ERCOT may, at its discretion, conduct an unannounced Generation Resource test. At a time determined solely by ERCOT, ERCOT will issue a Verbal Dispatch Instruction (VDI) to the QSE to operate the designated Generation Resource at its HSL as shown in the QSE's telemetry at the time the test is initiated. The QSE shall immediately upon receiving the VDI release all Ancillary Service Obligations carried by the unit to be tested and shall telemeter Resource Status as "ONTEST." The QSE shall not be required to start the designated Generation Resource if it is not already On-Line when ERCOT announces its intent to test the Resource. If the designated Generation Resource is operating at its LSL when ERCOT sends the VDI to begin the test, the QSE shall have up to 60 minutes to allow the Resource to reach 90% of its HSL as shown by telemetry and up to an additional 20 minutes for the Resource to reach the HSL shown by telemetry at the time the test is initiated. This time requirement does not apply to nuclear-fueled Generation Resources. If the designated Generation Resource is operating between its LSL and 50% of its HSL shown by telemetry when ERCOT begins the test, the QSE shall have 60 minutes for the Resource to reach its HSL. If the Resource is operating at or above 50% of its HSL shown by telemetry when ERCOT begins the test, the QSE shall have 30 minutes for the Resource to reach its HSL. Once the designated Generation Resource reaches its HSL, the QSE shall hold it at that output level for a minimum of 30 minutes. The HSL for the designated Generation Resource shall be determined based on the Real-Time averaged MW telemetered by the Resource during the 30 minutes of constant output. After each test, the QSE representing the Generation Resource will complete and submit the test form using the Net Dependable Capability and Reactive Capability (NDCRC) application located on the Market Information System (MIS) Secure Area within two Business Days.

[NPRR1011: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) To verify that the HSL reported by telemetry is achievable, ERCOT may, at its discretion, conduct an unannounced Generation Resource test. At a time determined solely by ERCOT, ERCOT will issue a Verbal Dispatch Instruction (VDI) to the QSE

to operate the designated Generation Resource at its HSL as shown in the QSE's telemetry at the time the test is initiated. Immediately upon receiving the VDI, the QSE shall telemeter Resource Status as "ONTEST." The QSE shall not be required to start the designated Generation Resource if it is not already On-Line when ERCOT announces its intent to test the Resource. If the designated Generation Resource is operating at its LSL when ERCOT sends the VDI to begin the test, the QSE shall have up to 60 minutes to allow the Resource to reach 90% of its HSL as shown by telemetry and up to an additional 20 minutes for the Resource to reach the HSL shown by telemetry at the time the test is initiated. This time requirement does not apply to nuclear-fueled Generation Resources. If the designated Generation Resource is operating between its LSL and 50% of its HSL shown by telemetry when ERCOT begins the test, the QSE shall have 60 minutes for the Resource to reach its HSL. If the Resource is operating at or above 50% of its HSL shown by telemetry when ERCOT begins the test, the QSE shall have 30 minutes for the Resource to reach its HSL. Once the designated Generation Resource reaches its HSL, the QSE shall hold it at that output level for a minimum of 30 minutes. The HSL for the designated Generation Resource shall be determined based on the Real-Time averaged MW telemetered by the Resource during the 30 minutes of constant output. After each test, the QSE representing the Generation Resource will complete and submit the test form using the Net Dependable Capability and Reactive Capability (NDCRC) application located on the Market Information System (MIS) Secure Area within two Business Days.

(3) ERCOT may test multiple Generation Resources within a single QSE within a single 24-hour period. However, in no case shall ERCOT test more than two Generation Resources within one QSE simultaneously. All Resources On-Line in a Combined-Cycle Configuration will be measured on an aggregate capacity basis. All QSEs associated with a jointly owned unit will be tested simultaneously. Hydro, wind, and PhotoVoltaic (PV) generation will be excluded from unannounced generation capacity testing. ERCOT shall not perform an unannounced Generation Resource test during a Watch or Energy Emergency Alert (EEA) event. If an unannounced Generation Resource test is underway when a Watch or EEA event commences, ERCOT may cancel the test.

(4) Should the designated Generation Resource fail to reach its HSL shown in its telemetry within the time frame set forth herein, the Real-Time averaged MW telemetered during the test shall be the basis for the new HSL for the designated Generation Resource for that Season. The QSE shall have the opportunity to request another test as quickly as possible (at a time determined by ERCOT) and may retest up to two times per month. The QSE may also demonstrate an increased value of HSL by operating the Generation Resource at an Output Schedule for at least 30 minutes. In order to raise an Output Schedule above the Seasonal HSL, the QSE may set the Resource telemetered HSL equal to its output temporarily for the purposes of the demonstration tests. After either a retest or a demonstration test, the MW capability of the Generation Resource based on the average of the MW production telemetered during the test shall be the basis for the new HSL for the designated Generation Resource for that Season. Any requested retest must take place within three Business Days after the request for retest.

(5) The telemetered value of HSL for the Generation Resource shall only be used for testing purposes as described in this Section or for system reliability calculations.

(6) A Resource Entity owning a hydro unit operating in the synchronous condenser fast response mode to provide hydro RRS shall evaluate the maximum capability of the Resource each Season.

[NPRR863: Replace paragraph (6) above with the following upon system implementation:]

(6) A Resource Entity owning a Generation Resource operating in the synchronous condenser fast response mode to provide RRS or ECRS shall evaluate the maximum capability of the Resource each Season.

(7) ERCOT shall maintain historical records of unannounced Generation Resource test results, using the information contained therein to adjust the Reserve Discount Factor (RDF) subject to the approval of the appropriate TAC subcommittee. ERCOT shall report to the Reliability and Operations Subcommittee (ROS) annually or as requested by ROS the aggregated results of such unannounced testing (excluding retests), including, but not limited to, the number and total capacity of Resources tested, the percentage of Resources that met or exceeded their HSL reported by telemetry, the percentage that failed to meet their HSL reported by telemetry, and the total MW capacity shortfall of those Resources that failed to meet their HSL reported by telemetry.

(8) QSEs who receive a VDI to operate the designated Generation Resource for an unannounced Generation Resource test may be considered for additional compensation under Section 6.6.9, Emergency Operations Settlement. Any unannounced Generation Resource test VDI that ERCOT issues as a result of a QSE-requested retest will not be considered for additional compensation under Section 6.6.9.

(9) All unannounced Generation Resource test VDIs will be considered as an instructed deviation for compliance purposes.

(10) Before the start of each Season, a QSE shall provide ERCOT a list identifying each Controllable Load Resource that is expected to operate in a Season as a provider of Ancillary Service. Prior to the beginning of each Season, QSEs shall identify the Controllable Load Resources to be tested during the Season and the specific week of the test if known. Any Controllable Load Resource for which the QSE desires qualification to provide Ancillary Services shall have its Net Dependable Capability verified prior to providing Ancillary Services.

(11) ERCOT shall verify the telemetry attributes of each qualified Load Resource as follows:

(a) ERCOT shall annually verify the telemetry attributes of each Load Resource providing RRS using a high-set under-frequency relay. In addition, once every two years, any Load Resource qualified to provide RRS using a high-set under-frequency relay shall test the correct operation of the under-frequency relay or the output from the solid-state switch, whichever applies. However, if a Load Resource's performance has been verified through response to an actual event, the data from the event can be used to meet the annual telemetry verification requirement for that year and the biennial relay-testing requirement.

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

(a) ERCOT shall annually verify the telemetry attributes of each Load Resource providing RRS or ECRS using a high-set under-frequency relay. In addition, once every two years, any Load Resource qualified to provide RRS or ECRS using a high-set under-frequency relay shall test the correct operation of the under-frequency relay or the output from the solid-state switch, whichever applies. However, if a Load Resource's performance has been verified through response to an actual event, the data from the event can be used to meet the annual telemetry verification requirement for that year and the biennial relay-testing requirement.

(b) ERCOT shall periodically validate the telemetry attributes of each Controllable Load Resource. In the case of an Aggregate Load Resource (ALR), ERCOT will follow the validation procedures described in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets." If a QSE fails to meet its telemetry validation requirements, ERCOT may suspend the QSE and/or the Controllable Load Resource from participation in the applicable services or markets. If disqualified pursuant to this paragraph, a QSE or Controllable Load Resource may reestablish its qualification by submitting a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and by successfully passing a new ERCOT telemetry validation test.

(12) Telemetry values of a Load Resource may be adjusted to reflect Distribution Losses, based on the ERCOT-forecasted Distribution Loss Factors (DLFs). Load Resources may be adjusted for Distribution Losses using the same distribution loss code as assigned to the ESI ID.

(13) A specific Load Resource to be used for the first time to provide Regulation, RRS, Non-Spin or energy by following Security-Constrained Economic Dispatch (SCED) Base Points, must be tested to ERCOT's reasonable satisfaction using actual Demand response as part of its qualification. The test must take place at a time mutually selected by the QSE representing the Load Resource and ERCOT. ERCOT shall make available its standard test document for Load Resource qualification required under this Section on the ERCOT website.

[NPRR863: Replace paragraph (13) above with the following upon system implementation:]

(13) A specific Load Resource to be used for the first time to provide Regulation, RRS, ECRS, Non-Spin or energy by following Security-Constrained Economic Dispatch (SCED) Base Points, must be tested to ERCOT's reasonable satisfaction using actual Demand response as part of its qualification. The test must take place at a time mutually selected by the QSE representing the Load Resource and ERCOT. ERCOT shall make available its standard test document for Load Resource qualification required under this Section on the ERCOT website.

(14) Any changes to a Load Resource including changes to its capability to provide Ancillary Service requires updates by the Load Resource to the registration information detailing the change. For Non-Opt-In Entities (NOIEs) representing specific Load Resources that are located behind the NOIE Settlement Metering points, the NOIE shall provide an alternative unique descriptor of the qualified Load Resource for ERCOT's records.

(15) Qualification of a Resource, including a Load Resource, remains valid for that Resource in the event of a change of QSE for the Resource, provided that the new QSE demonstrates to ERCOT's reasonable satisfaction that the new QSE has adequate communications and control capability for the Resource.

(16) For purposes of qualifying Quick Start Generation Resources (QSGRs), ERCOT shall issue a unit-specific VDI for the MW amount that the QSE is requesting to qualify its QSGR to provide. The QSE shall telemeter an ONTEST Resource Status. The QSGR will only be qualified to provide an amount not to exceed the observed output at the end of a ten-minute test period.

(17) ERCOT may revoke the QSGR qualification of any QSGR for failure to comply with the following performance standard:

(a) A QSGR, available for deployment by SCED, is deemed to have failed to start for the purpose of this performance measure if the QSGR fails to achieve at least 90% of the minimum ERCOT SCED Base Point, including zero Base Points, within ten minutes of the initial ERCOT SCED Base Point that dispatched the QSGR above zero MW output.

(b) ERCOT may revoke a QSGR's qualification if within a rolling 90-day period the number of QSGR failures to start, as determined by paragraph (a) above, exceeds the higher of three failures or 10% of the number of quick start mode startups made in response to SCED deployments.

(18) If disqualified pursuant to paragraph (17) above, a QSGR may reestablish its QSGR qualification by submitting a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and by successfully passing a new ERCOT QSGR test.

(19) If an Energy Storage Resource (ESR) is telemetering a non-zero Non-Spin Ancillary Service Resource Responsibility, to verify that the Ancillary Service Resource Responsibility reported by telemetry is achievable based on the state of charge the

Resource is maintaining in Real-Time, ERCOT may, at its discretion, conduct an unannounced Non-Spin capability test. At a time determined solely by ERCOT, ERCOT will issue a VDI to the QSE to operate the designated ESR an output level that delivers the total state of charge the ESR was obligated to provide based on the Non-Spin Ancillary Service Resource Responsibility as shown in the ESR's telemetry at the time the test is initiated. The QSE shall immediately upon receiving the VDI release all Ancillary Service Obligations carried by the ESR to be tested and shall telemeter Resource Status as "ONTEST." Once the designated ESR reaches the target output level, the QSE shall hold at that output level for a minimum duration required to verify ESR's state of charge capability to meet the Non-Spin Ancillary Service Resource Responsibility. The four-hour capability for the designated ESR shall be determined based on the Real-Time averaged MW telemetered by the Resource during the constant output (i.e., hold) phase of the test. After each test, the QSE representing the ESR will complete and submit the test form using the NDCRC application located on the MIS Secure Area within two Business Days. Should the designated ESR fail to demonstrate the state of charge level needed to meet the Non-Spin Ancillary Service Resource Responsibility shown in its telemetry within the time frame set forth herein, the Real-Time averaged MW telemetered during the test shall be the basis for the Non-Spin capacity that the Resource may provide. The QSE shall have the opportunity to request another test as quickly as possible (at a time determined by ERCOT) and may retest up to two times per month. After either a retest or a demonstration test, the average of the MW output telemetered during the test shall be the basis for the new Non-Spin capability for the designated ESR. Any requested retest must take place within three Business Days after the request for retest or a mutually agreeable date.

[NPRR1096: Replace paragraph (19) above with the following upon system implementation of NPRR863:]

(19) If an Energy Storage Resource (ESR) is telemetering a non-zero ECRS Ancillary Service Responsibility and/or non-zero Non-Spin Ancillary Service Responsibility, to verify that the Ancillary Service Responsibility reported by telemetry is achievable based on the state of charge the Resource is maintaining in Real-Time, ERCOT may, at its discretion, conduct an unannounced ECRS/Non-Spin capability test. At a time determined solely by ERCOT, ERCOT will issue a VDI to the QSE to operate the designated ESR an output level that delivers the total state of charge the ESR was obligated to provide based on sum of the ECRS Ancillary Service Responsibility and Non-Spin Ancillary Service Responsibility as shown in the ESR's telemetry at the time the test is initiated. The QSE shall immediately upon receiving the VDI release all Ancillary Service Obligations carried by the ESR to be tested and shall telemeter Resource Status as "ONTEST." Once the designated ESR reaches the target output level, the QSE shall hold at that output level for a minimum duration required to verify ESR's state of charge capability to meet the ECRS Ancillary Service Responsibility and Non-Spin Ancillary Service Responsibility. The two-hour and/or four-hour capability for the designated ESR shall be determined based on the Real-Time averaged MW telemetered by the Resource during the constant output (i.e., hold) phase of the test. After each test, the QSE representing the ESR will complete and submit the

test form using the NDCRC application located on the MIS Secure Area within two Business Days. Should the designated ESR fail to demonstrate the state of charge level needed to meet the sum of ECRS Ancillary Service Responsibility and Non-Spin Ancillary Service Responsibility shown in its telemetry within the time frame set forth herein, the Real-Time averaged MW telemetered during the test shall be the basis for the ECRS and Non-Spin capacity that the Resource may provide. The QSE shall have the opportunity to request another test as quickly as possible (at a time determined by ERCOT) and may retest up to two times per month. After either a retest or a demonstration test, the average of the MW output telemetered during the test shall be the basis for the new ECRS and Non-Spin capability for the designated ESR. Any requested retest must take place within three Business Days after the request for retest or a mutually agreeable date.

8.1.1.2.1 Ancillary Service Technical Requirements and Qualification Criteria and Test Methods

(1) A QSE and the Resource that it represents must be qualified to provide Ancillary Services. ERCOT shall develop and operate a qualification and testing program that meets the requirements of this Section for each Ancillary Service. Prior to the Texas Nodal Market Implementation Date, a QSE and the Resources that it represents that are qualified to provide an Ancillary Service in accordance with an effective Protocol, are deemed to be qualified to provide Ancillary Services after the Texas Nodal Market Implementation Date, provided that the QSE and the Resource have been certified capable of providing an Ancillary Service by a responsible Market Participant, as determined by ERCOT. Resources that are thus certified to provide Ancillary Services and that have a performance history determined in accordance with this Section, and that fail to meet the performance metrics described in this Section on the Texas Nodal Market Implementation Date, or thereafter, will be required to qualify in accordance with this Section before providing the Ancillary Service.

(2) A QSE and the Resource that it represents must be qualified in accordance with this Section as an Ancillary Service and reserve provider and at ERCOT's discretion will be required to re-qualify to provide Ancillary Service or reserve if acceptable performance as determined in accordance with this Section has not been maintained.

[NPRR1011: Insert paragraph (3) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) The qualification process for a Resource to provide Ancillary Service will determine whether the Resource is capable of providing Ancillary Service and the maximum quantity of Ancillary Service that the Resource is qualified to provide. ERCOT may update the maximum quantity of RRS a Resource is qualified to provide based on actual performance of the Resource in accordance with Section 8.1.1.2.1.2, Responsive Reserve Service Qualification.

8.1.1.2.1.1 Regulation Service Qualification

(1) A QSE control system must be capable of receiving Regulation Up Service (Reg-Up) and Regulation Down Service (Reg-Down) control signals from ERCOT's Load Frequency Control (LFC) system, and of directing its Resources to respond to the control signals, in an upward and downward direction to balance Real-Time Demand and Resources. A QSE providing Reg-Up or Reg-Down shall provide communications equipment to receive telemetered control deployments of power from ERCOT.

[NPRR1011 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011; or upon system implementation for NPRR1014:]

(1) A QSE control system must be capable of receiving Regulation Up Service (Reg-Up) and Regulation Down Service (Reg-Down) control signals from ERCOT's Load Frequency Control (LFC) system, and of directing its Resources to respond to the control signals, in an upward and downward direction to balance Real-Time Demand and Resources. A QSE representing Resources qualified to provide Reg-Up or Reg-Down shall provide communications equipment to receive telemetered control deployments of power from ERCOT.

(2) A QSE shall demonstrate to ERCOT that they have the ability to switch control to constant frequency operation as specified in the Operating Guides. ERCOT's direction to the QSE to operate on constant frequency will be considered a Dispatch Instruction.

(3) A QSE providing Reg-Up or Reg-Down shall provide ERCOT with the data requirements of Section 6.5.5.2, Operational Data Requirements. Resources providing Reg-Up or Reg-Down must be capable of delivering the full amount of regulating capacity offered to ERCOT within five minutes.

(4) A Resource providing Fast Responding Regulation Service (FRRS) shall be capable of independently detecting and recording system frequency with an accuracy of at least one mHz and a resolution of no less than 32 samples per second. The Resource shall also be capable of measuring and recording MW output with a resolution of no less than 32 samples per second.

[NPRR1011 and NPRR1014: Delete paragraph (4) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011; or upon system implementation for NPRR1014; and renumber accordingly.]

(5) A Reg-Up and Reg-Down qualification test for each Resource is conducted during a continuous 60-minute period agreed on in advance by the QSE and ERCOT. QSEs may qualify a Resource to provide Reg-Up or Reg-Down, or both, in separate testing. ERCOT shall administer the following test requirements:

(a) ERCOT shall confirm the date and time of the test with the QSE.

(b) For the 60-minute duration of the test, when market and reliability conditions allow, the ERCOT Control Area Operator shall send a random sequence of increasing ramp, hold, and decreasing ramp control signals to the QSE for a specific Resource. ERCOT shall maintain a duration interval, for each increasing ramp, hold, or decreasing ramp sequence, of no less than two minutes. The control signals may not request Resource performance beyond the HSL, LSL, and ramp rate limit agreed on prior to the test. During the test, ERCOT shall structure the test sequence such that at least one five-minute test interval is used to test the Resource's ability to achieve the entire amount of Reg-Up or Reg-Down requested for qualification.

(c) ERCOT shall measure and record the average real power output for each minute of the Resource(s) being tested represented by the QSE. During at least one five minute duration interval selected to evaluate each of the Reg-Up and Reg-Down amounts being tested, the Generation/Controllable Load Resource Energy Deployment Performance (GREDP/CLREDP) calculated in accordance with Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance, over the entire five minute interval must be less than or equal to 3.5%. Additionally, in all other test sequence intervals, the Resource's measured GREDP/CLREDP must be less than or equal to 5% as calculated for the entire duration of each test interval.

[NPRR963 and NPRR1014: Replace applicable portions of paragraph (c) above with the following upon system implementation:]

(c) ERCOT shall measure and record the average real power output for each minute of the Resource(s) being tested represented by the QSE.

(i) During at least one five minute duration interval selected to evaluate each of the Reg-Up and Reg-Down amounts being tested, the Generation/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance (GREDP/CLREDP/ESREDP) calculated in accordance with Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, over the entire five minute interval must be less than or equal to 3.5%.

(ii) Additionally, in all other test sequence intervals, the Resource's measured GREDP/CLREDP/ESREDP must be less than or equal to 5% as calculated for the entire duration of each test interval.

(iii) During at least one five-minute duration interval selected to evaluate each of the Reg-Up and Reg-Down amounts being tested, the Energy Storage Resource Energy Deployment Performance (ESREDP) calculated in accordance with Section 8.1.1.4.1, Regulation Service and

Generation Resource/Controllable Load Resource Energy Deployment Performance, over the entire five minute interval must be less than or equal to 3.0%.

(iv) For an Energy Storage Resource (ESR), in all other test sequence intervals, the Resource's measured ESREDP must be less than or equal to 3.0% as calculated for the entire duration of each test interval.

(d) On successful demonstration of the above test criteria, ERCOT shall qualify that the Resource is capable of providing Regulation Service and shall provide a copy of the certificate to the QSE and the Resource.

(6) A QSE may also qualify a Resource to provide Fast Responding Regulation Up Service (FRRS-Up), Fast Responding Regulation Down Service (FRRS-Down), or both. In addition to the test criteria described in paragraph (5) above, ERCOT shall verify the following capabilities through testing:

(a) The Resource will be required to demonstrate that it can deploy within 60 cycles of either (i) receipt of a deployment signal from ERCOT, or (ii) a deviation of frequency in excess of +/-0.09 Hz from 60 Hz.

(b) Upon deployment, the Resource will be required to demonstrate that it can sustain the deployment for a minimum of eight minutes at a minimum level of 95% and a maximum level of 110% of the proposed maximum capacity obligation.

(c) ERCOT shall use the Resource's high-resolution recorded frequency and MW output data to determine whether the Resource met its performance obligations during the test.

(d) On successful demonstration of the above test criteria, ERCOT shall qualify that the Resource is capable of providing FRRS and shall provide a copy of the certificate to the QSE and the Resource.

(e) A QSE representing a Resource qualified to provide FRRS shall not offer to provide more FRRS than the maximum capacity obligation that the Resource is qualified to provide, as shown in the certificate provided to the QSE and the Resource.

[NPRR1011 and NPRR1014: Replace applicable portions of paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011; or upon system implementation for NPRR1014:]

(5) The maximum quantity of Reg-Up or Reg-Down that an individual Resource is qualified to provide is limited to the amount of Ancillary Service that can be sustained by the Resource for at least 15 minutes.

8.1.1.2.1.2 Responsive Reserve Service Qualification

(1) RRS may be provided by:

  (a) Unloaded Generation Resources that are On-Line;

  (b) Load Resources controlled by high-set under-frequency relays;

  (c) Hydro RRS; or

  (d) Controllable Load Resources.

(2) The amount of RRS provided by individual Generation Resources and Controllable Load Resources is specified in the Operating Guides. Each Resource providing RRS must be On-Line and capable of ramping the Resource’s Ancillary Service Resources Responsibility for RRS within ten minutes of the notice to deploy RRS, must be immediately responsive to system frequency, and must be able to maintain the scheduled level of deployment for the period of service commitment. The amount of RRS on a Generation Resource may be further limited by requirements of the Operating Guides.

(3) A QSE’s Load Resource must be loaded and capable of unloading the scheduled amount of RRS within ten minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays with settings as specified by the Operating Guides.

(4) Any QSE providing RRS shall provide communications equipment to receive ERCOT telemetered control deployments of RRS.

(5) Generation Resources providing RRS shall have their governors in service.

(6) Load Resources on high-set under-frequency relays providing RRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay.

(7) Each QSE shall ensure that each Resource is able to meet the Resource’s obligations to provide the Ancillary Service Resource Responsibility. Each Generation Resource and Load Resource providing RRS must meet additional technical requirements specified in this Section.

(8) A qualification test for each Resource to provide RRS is conducted during a continuous eight-hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements:

  (a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE it is to provide an amount of RRS from its Resource to be qualified equal to the amount that the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) For Generation Resources desiring qualification to provide RRS, ERCOT shall send a signal to the Resource's QSE to deploy RRS, indicating the MW amount. ERCOT shall monitor the QSEs telemetry of the Resource's Ancillary Service Schedule for an update within 15 seconds. ERCOT shall measure the test Resource's response as described under Section 8.1.1.4.2, Responsive Reserve Service Energy Deployment Criteria. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource's qualification to provide RRS.

(c) For Controllable Load Resources desiring qualification to provide RRS, ERCOT shall send a signal to the Resource's QSE to deploy RRS, indicating the MW amount. ERCOT shall measure the test Resource's response as described under Section 8.1.1.4.2. ERCOT shall evaluate the response of the Controllable Load Resource given the current operating conditions of the system and determine the Controllable Load Resource's qualification to provide RRS.

(d) For Load Resources, excluding Controllable Load Resources, desiring qualification to provide RRS, ERCOT shall deploy RRS, indicating the MW amount. ERCOT shall measure the test Resource's response as described under Section 8.1.1.4.2.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing RRS and shall provide a copy of the certificate to the QSE and the Resource Entity.

[NPRR863, NPRR1011, and NPRR1014: Replace applicable portions of Section 8.1.1.2.1.2 above with the following upon system implementation for NPRR863 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.2.1.2 Responsive Reserve Qualification

(1) RRS may be provided by:

(a) On-Line Generation Resource capacity;

(b) Resources capable of providing FFR;

(c) Generation Resources operating in the synchronous condenser fast-response mode;

(d) Load Resources controlled by high-set under-frequency relays; and

(e) Energy Storage Resources (ESRs).

(2) The amount of RRS provided by individual Generation Resources or ESRs is limited by the ERCOT-calculated maximum MW amount of RRS for the Generation Resource or ESR subject to its verified droop performance as described in the Nodal Operating

Guide. The default value for any newly qualified Generation Resource or ESR shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide.

(3) Any QSE representing a Resource qualified to provide RRS shall provide communications equipment to provide ERCOT with telemetry for the output of the Resource.

(4) Resources capable of FFR providing RRS must provide a telemetered output signal, including breaker status and status of the frequency detection device.

(5) Each QSE shall ensure that each Resource is able to meet the Resource's obligations to provide the RRS award. Each Resource providing RRS must meet additional technical requirements specified in this Section.

(6) Generation Resources offering to provide RRS shall have their Governors in service.

(7) Generation Resources and Resources capable of FFR providing RRS shall have a Governor droop setting that is no greater than 5.0%.

(8) Resources may be provisionally qualified by ERCOT to provide RRS for 90 days. Within the 90-day provisional window, a Resource must successfully complete one of the Governor tests identified in the Nodal Operating Guide Section 8, Attachment C, Turbine Governor Speed Tests, before being declared fully qualified to provide RRS.

(9) For Resources providing RRS and available for dispatch by SCED, the maximum quantity of RRS that a Resource is qualified to provide is limited to the amount of RRS that can be sustained by the Resource for at least 15 minutes. For all other Resources excluding non-Controllable Load Resources providing FFR, the maximum quantity of RRS that a Resource is qualified to provide is limited to the amount of RRS that can be sustained by the Resource for at least one hour. The maximum quantity of FFR that any non-Controllable Load Resource qualified to provide FFR is limited to the amount of FFR that can be sustained by the Resource for at least 15 minutes.

8.1.1.2.1.3 Non-Spinning Reserve Qualification

(1) Each Resource providing Non-Spin must be capable of being synchronized and ramped to its Ancillary Service Schedule for Non-Spin within 30 minutes. Non-Spin may be provided from Generation Resource capacity that can ramp within 30 minutes or Load Resources capable of unloading within 30 minutes. Non-Spin may only be provided from capacity that is not fulfilling any other energy or capacity commitment.

(2) A Load Resource providing Non-Spin must provide a telemetered output signal.

(3) Each Generation Resource and Load Resource providing Non-Spin must meet additional technical requirements specified in this Section.

(4) QSEs using a Controllable Load Resource to provide Non-Spin must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resource to provide Non-Spin.

(5) Each QSE shall ensure that each Resource is able to meet the Resource's obligations to provide the Ancillary Service Resource Responsibility. Each Generation Resource and Controllable Load Resource providing Non-Spin must meet additional technical requirements specified in this Section.

(6) For any Resource requesting qualification for Non-Spin, a qualification test for each Resource to provide Non-Spin is conducted during a continuous eight hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements.

(a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE by using the messaging system and requesting that the QSE provide an amount of Non-Spin from each Resource equal to the amount for which the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) For Generation Resources: during the test window, ERCOT shall send a message to the QSE representing a Generation Resources to deploy Non-Spin. ERCOT shall monitor the adjustment of the Generation Resource's Non-Spin Ancillary Service Schedule within five minutes for Resources On-Line. ERCOT shall measure the test Resource's response as described under Section 8.1.1.4.3, Non-Spinning Reserve Service Energy Deployment Criteria. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource's qualification to provide Non-Spin.

(c) For Load Resources, ERCOT shall send an instruction to deploy Non-Spin. ERCOT shall measure the Resource's response as described under Section 8.1.1.4.3.

[NPRR1011: Replace Section 8.1.1.2.1.3 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

8.1.1.2.1.3 Non-Spinning Reserve Qualification

(1) Each Off-Line Resource being offered in to provide Non-Spin must be capable of being synchronized and ramped to its Ancillary Service award for Non-Spin within 30 minutes. Non-Spin may be provided from Generation Resource capacity that can ramp within 30 minutes or Load Resources capable of unloading within 30 minutes. Non-

Spin may only be provided from capacity that is not fulfilling any other energy or capacity commitment.

(2) All Resources qualified to participate in SCED are also qualified to provide Non-Spin when the Resource is On-Line. The amount of Non-Spin for which the Resource is qualified when On-Line is limited to the amount of capacity that can be ramped or unloaded within 30 minutes.

(3) A Controllable Load Resource offering to provide Non-Spin must be qualified to participate in SCED and must provide a telemetered output signal, including breaker status.

(4) Each Resource providing Non-Spin when Off-Line or providing Non-Spin as a Load Resource other than a Controllable Load Resource must meet additional technical requirements specified in this Section.

(5) QSEs using a Controllable Load Resource to provide Non-Spin must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resource to provide Non-Spin.

(6) Each QSE shall ensure that each Resource is able to meet the Resource's obligations to provide the Ancillary Service award.

(7) For any Resource requesting qualification for providing Non-Spin when Off-Line or providing Non-Spin as a Load Resource other than a Controllable Load Resource, a qualification test for each Resource to provide Non-Spin is conducted during a continuous eight hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements.

(a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE by using the messaging system and requesting that the QSE provide an amount of Non-Spin from each Resource equal to the amount for which the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) For the Resources being tested during the test window, ERCOT shall send a message to the QSE representing a Resource to deploy Non-Spin. ERCOT shall measure the test Resource's response as described under Section 8.1.1.4.3, Non-Spinning Reserve Service Energy Deployment Criteria. ERCOT shall evaluate the response of the Resource given the current operating conditions of the system and determine the Resource's qualification to provide Non-Spin.

(8) The maximum quantity of Non-Spin that an individual Resource is qualified to provide is limited to the amount of Non-Spin that can be sustained by the Resource for at least one hour.

8.1.1.2.1.4 Voltage Support Service Qualification

(1) The Resource Entity must verify and maintain its stated Reactive Power capability for each of its Generation Resources providing Voltage Support Service (VSS), as required by the Operating Guides. Generation Resources providing VSS reactive capability limits shall be specified as follows: lagging reactive capability should be specified using the Summer/Fall voltage profile, and leading capability specified using the Winter/Spring voltage profile.

[NPRR989: Replace paragraph (1) above with the following upon system implementation:]

(1) The Resource Entity must verify and maintain its stated Reactive Power capability for each of its Generation Resources and ESRs providing Voltage Support Service (VSS), as required by the Operating Guides. Generation Resources and ESRs providing VSS reactive capability limits shall be specified as follows: lagging reactive capability should be specified using the Summer/Fall voltage profile, and leading capability specified using the Winter/Spring voltage profile.

(2) The Resource Entity shall conduct reactive capacity qualification tests to verify the maximum leading and lagging reactive capability of all Generation Resources required to provide VSS. Reactive capability tests are performed during the resource commissioning process and at a minimum of once every five years or within 12 months following the discovery of a change that affects its real power or Reactive Power capability by more than 10% of the last value provided by the Resource Entity via the Resource Registration process and is expected to last more than six months. Mothballed Generation Resources that have not been tested within the last five years shall be verified within 12 calendar months upon return to service. ERCOT may require additional testing if it has information indicating that current data is inaccurate. The Resource Entity is not obligated to place Generation Resources On-Line solely for the purposes of testing. The reactive capability tests must be conducted at a time agreed to in advance by the Resource Entity, its QSE, the applicable TSP, and ERCOT.

[NPRR989: Replace paragraph (2) above with the following upon system implementation:]

(2) The Resource Entity shall conduct reactive capacity qualification tests to verify the maximum leading and lagging reactive capability of all Generation Resources and ESRs required to provide VSS. Reactive capability tests are performed during the resource commissioning process and at a minimum of once every five years or within 12 months following the discovery of a change that affects its real power or Reactive Power capability by more than 10% of the last value provided by the Resource Entity via the Resource Registration process and is expected to last more than six months. Mothballed Generation Resources or ESRs that have not been tested within the last five years shall be verified within 12 calendar months upon return to service. ERCOT may require additional testing if it has information indicating that current data is inaccurate. The Resource Entity is not obligated to place Generation Resources or

ESRs On-Line solely for the purposes of testing. The reactive capability tests must be conducted at a time agreed to in advance by the Resource Entity, its QSE, the applicable TSP, and ERCOT.

(3) Leading and lagging reactive operating limits must be demonstrated following the reactive power verification test procedure as more fully described in Nodal Operating Guide Section 3.3.2, Unit Reactive Capability Requirements.

(4) The Resource Entity shall perform the Automatic Voltage Regulator (AVR) tests and shall supply AVR data as specified in the Operating Guides. The AVR tests must be performed on initial qualification. The AVR tests must be conducted at a time agreed on in advance by the Resource Entity, its QSE, the applicable TSP, and ERCOT.

8.1.1.2.1.5 System Black Start Capability Qualification and Testing

(1) A Resource is qualified to be a Black Start Resource if it has met the following requirements:

(a) Verified control communication path performance;

(b) Verified primary and alternate voice circuits for receipt of instructions;

(c) Passed the “Basic Starting Test” as defined below;

(d) Passed the “Line-Energizing Test” as defined below;

(e) Passed the “Load-Carrying Test” as defined below;

(f) Passed the “Next Start Resource Test” as defined below;

(g) Provided an attestation, in the form required by ERCOT, of Black Start Service (BSS) Back-up Fuel that will support the Resource for a minimum of 72 hours at maximum output, except to the extent ERCOT has waived this requirement;

(h) Passed the “BSS Back-up Fuel Switching Test” as defined below, unless ERCOT has waived the BSS Back-up Fuel requirement;

(i) If not starting itself, has an ERCOT-approved firm standby power contract with deliverability under Blackout circumstances from a non-ERCOT Control Area that can be finalized upon selection as a Black Start Resource;

(j) If not starting itself, has an ERCOT approved agreement with the necessary TSPs for access to another power pool, for coordination of switching during a Blackout or Partial Blackout, for coordination of maintenance through the ERCOT Outage Scheduler for all non-redundant transmission startup feeds;

(k) If dependent upon non-ERCOT transmission resources, agreements providing this Transmission Service have been provided in the proposal; and

(l) Demonstrated to ERCOT's satisfaction that the Resource has successfully completed remediation to any weather-related limitation disclosed as part of the BSS bid.

(2) On successful demonstration of system BSS capability, ERCOT shall certify that the Black Start Resource is capable of providing system BSS capacity and shall provide a copy of the certificate to the Resource Entity of the Black Start Resource. Qualification shall be valid for the time frames set forth below. Except under extenuating circumstances, as reasonably determined by ERCOT, all qualification testing for the next year of BSS must be completed by June 1st of each year.

(3) ERCOT may limit the number of qualification retests allowed. Qualification retesting is required only for the aspect of system BSS capability for which the Black Start Resource failed. If a Black Start Resource under an existing Black Start Agreement does not successfully re-qualify within two months of failing a test described herein, ERCOT shall decertify the Black Start Resource for the remainder of the calendar year as described in Section 7, Black Start Decertification, of Section 22, Attachment D, Standard Form Black Start Agreement. The following tests are required for BSS qualification:

(a) The "Basic Starting Test" includes the following:

(i) The basic ability of the Black Start Resource to start itself, or start from a normally open interconnection to another provider not inside the ERCOT interconnection, without support from the ERCOT System;

(ii) Annual testing, either as a stand-alone test or part of the Line-Energizing and Load-Carrying Tests, and the test is performed during a one-week period agreed to in advance by the Black Start Resource and ERCOT and must not cause outage to ERCOT Customer Load or the availability of other Resources to the ERCOT market;

(iii) Confirmation of the dates of the test with the Black Start Resource by ERCOT;

(iv) Isolation of the Black Start Resource, including all auxiliary Loads, from the ERCOT System, except for the transmission that connects the Resource to a provider not inside the ERCOT interconnection if the startup power is supplied by a firm standby contract. Black Start Resources starting with the assistance of a provider not inside the ERCOT interconnection through a firm standby agreement will connect to provider not inside the ERCOT interconnection, start-up, carry internal Load, disconnect from the provider not inside the ERCOT interconnection if not supplied through a black-start capable Direct Current Tie (DC Tie), and continue equivalently to what is required of other Black Start Resources;

(v) The ability of the Black Start Resource to start without assistance from the ERCOT System, except for the transmission that connects the Resource to a provider not inside the ERCOT interconnection if the startup power is supplied by a firm standby contract;

(vi) The ability of the Black Start Resource to remain stable (in both frequency and voltage) while supplying only its own auxiliary Loads or Loads in the immediate area for at least 30 minutes;

(vii) The Black Start Resource must have verified that its Volts/Hz relay, over-excitation limiter, and under-excitation limiter are set properly and that no protection devices will trip the Black Start Resource within the required reactive range. The Resource Entity for the Black Start Resource shall provide ERCOT with data to verify these settings; and

(viii) Each Black Start Resource must pass a Basic Starting Test once each calendar year.

(b) The "Line-Energizing Test" must be conducted at a time agreed on by the Black Start Resource, TSP or Distribution Service Provider (DSP), and ERCOT and includes the following:

(i) Energizing transmission with the Black Start Resource when conditions permit as determined by the TSP or DSP but at least once every three years;

(ii) De-energizing sufficient transmission in such manner that when energized by the Black Start Resource it demonstrates the Black Start Resource's ability to energize enough transmission to deliver to the Loads the Resource's output that ERCOT's restoration plan requires the Black Start Resource to supply. ERCOT shall be responsible for transmission connections and operations that are compatible with the capabilities of the Black Start Resource;

(iii) Conducting a Basic Starting Test;

(iv) Energizing transmission with the Black Start Resource of the previously de-energized transmission, while monitoring frequency and voltages at both ends of the line. Alternatively, if ERCOT agrees, the transmission line may be connected to the Black Start Resource before starting, allowing the Resource to energize the line as it comes up to speed;

(v) Stable operation of the Black Start Resource (in both frequency and voltage) while supplying only its auxiliary Loads or external Loads for at least 30 minutes;

(vi) This test may be performed together with the Basic Starting Test in one 30-minute interval; and

(vii) Each Black Start Resource must pass a Line-Energizing Test once every three years.

(c) The "Load-Carrying Test" shall utilize the Load agreed to between ERCOT, TSP and the Black Start Resource. Testing shall occur as conditions permit, at a time agreed on by the Black Start Resource, TSP or DSP, and ERCOT, and includes the following:

(i) Stable operation of the Black Start Resource (in both frequency and voltage) while supplying restoration power to Load that is not identified as auxiliary Load of the Resource and is allowed to be auxiliary Load of adjacent facilities;

(ii) Conducting a Basic Starting Test;

(iii) Conducting a Line-Energizing Test when required;

(iv) Under the direction of ERCOT or the TSP operator, the Black Start Resource shall demonstrate the Black Start Resource's capability to supply the required Load, while maintaining voltage and frequency for at least 30 minutes;

(v) This test may be performed together with the Basic Starting Test and Line-Energizing Test when required in one 30-minute interval; and

(vi) Qualification under the Load-Carrying Test is valid for five years.

(d) "Next Start Resource Test":

(i) The ability of a Black Start Resource to start up the next start unit's largest required motor while continuing to remain stable and control voltage and frequency shall be tested. This test shall be repeated when a new next start unit is selected;

(ii) To pass the test:

(A) The potential Black Start Resource must start the next start unit (as determined by ERCOT), or start the next start unit's largest required motor and satisfied the next start unit's minimum startup Load requirements; or

(B) The Resource Entity shall demonstrate to the satisfaction of ERCOT through simulation studies conducted by the Resource Entity or a qualified third party, that the potential Black Start Resource is capable of starting the next start unit's largest required motor while meeting the next start unit's minimum startup Load requirements.

(iii) Potential Black Start Resources may request from ERCOT the information detailed in paragraph (B) above of the next start unit prior to the satisfaction of this requirement. ERCOT shall request this information from the designated next start unit. Such data, if requested by ERCOT, shall be provided by the QSE or Resource Entity representing the next start unit to ERCOT within 30 days. Such information shall be considered Protected Information by the requesting Resource Entity;

(iv) If a physical test is performed, the test shall commence with a Basic Starting Test, followed by a Line-Energizing Test when required and a Load-Carrying Test as a stand-alone test or part of the Next Start Resource Test;

(v) If a physical test is performed, the Black Start Resource must remain stable (in both voltage and frequency) and controlling voltage for 30 minutes;

(vi) If a physical test is performed, this test may be performed together with the Basic Starting Test, Line-Energizing Test when required, and Load-Carrying Test in one 30-minute interval; and

(vii) Each Black Start Resource must pass the Next Start Resource Test once every five years.

(e) The “BSS Back-up Fuel Switching Test” shall:

(i) Demonstrate a Black Start Resource’s ability to successfully switch to a BSS Back-up Fuel source;

(ii) Demonstrate the ability of the Black Start Resource to start itself, or start from a normally open interconnection to another provider not inside the ERCOT interconnection, without support from the ERCOT System and while operating on the BSS Back-up Fuel source. The Black Start Resource may start on its primary fuel source, if necessary, but must transition to the BSS Back-up Fuel source within the timeframe indicated in its proposal;

(iii) Demonstrate the ability of the Black Start Resource to remain stable (in both frequency and voltage) while operating on BSS Back-up Fuel source and supplying only its own auxiliary Loads or Loads in the immediate area for at least ten minutes; and

(iv) Demonstrate that there is a sufficient amount of BSS Back-up Fuel to satisfy the requirement in paragraph (10) of Section 3.14.2, Black Start.

(f) The BSS Back-up Fuel Switching Test will be conducted on odd numbered years and may, at ERCOT’s discretion, also be:

(i) Performed as part of the Basic Starting Test while operating on BSS Back-up Fuel; or

(ii) As a stand-alone test.

(4) Each qualified Black Start Resource shall perform a Black Start Resource Availability Test quarterly unless the Black Start Resource has successfully started and operated at LSL or higher for at least four consecutive Settlement Intervals during the quarter. The Black Start Resource's cost to perform a Black Start Availability Test may be a component of the overall bid for BSS but ERCOT will not separately compensate QSEs representing Black Start Resources for such testing. ERCOT, at its sole discretion, may grant an exemption of the Black Start Resource Availability Test for QSEs whose Black Start Resources have responded as instructed by ERCOT during an EEA event.

(5) The Black Start Resource Availability Test shall be scheduled by ERCOT. Upon receipt of notification for a Black Start Resource Availability Test, the QSE representing the Black Start Resource shall send confirmation to ERCOT of its intent to comply with the test or submit a request to reschedule along with justification for the request.

(6) ERCOT shall provide the QSE representing the Black Start Resource two-hour notice in order to allow the QSE time to update its COP. The QSE representing the Black Start Resource shall show the Resource as "ONTEST" in its COP and through its Real-Time telemetry for the duration of the test. As part of the Black Start Resource Availability Test, the QSE representing the Black Start Resource shall start the Black Start Resource and operate it at or above its LSL for at least four consecutive Settlement Intervals. After completion of the Black Start Resource Availability Test the QSE will update its COP to reflect their current status.

(7) Upon completion of the Black Start Resource Availability Test, the QSE representing the Black Start Resource shall complete and file a Black Start Resource Availability Test report with ERCOT. If the Black Start Resource wants to use a successful start and normal operation to satisfy the quarterly reporting requirement, it must provide the necessary information for the start and normal operation on a Black Start Resource Availability Test report. The report form shall be provided by ERCOT.

(8) A Black Start Resource Availability Test is deemed to be successful if the Black Start Resource comes On-Line within the time specified in the Black Start Resource's Request for Proposal response submitted to ERCOT and operates at a minimum level as agreed to by ERCOT and the QSE representing the Black Start Resource for at least four consecutive Settlement Intervals.

(9) If the Black Start Resource fails to successfully start during the Black Start Resource Availability Test, the QSE representing the Black Start Resource shall immediately update its Availability Plan for that Black Start Resource showing zero availability. The QSE representing the Black Start Resource shall not receive the Hourly Standby Fee for BSS effective from the date of the failed Black Start Resource Availability Test. The QSE representing the Black Start Resource may schedule a second Black Start Resource

Availability Test, subject to ERCOT approval, to be completed within ten Business Days of the date of the failed Black Start Resource Availability Test unless a later date is agreed to by ERCOT. The cost of the second Black Start Resource test will be borne solely by the QSE representing the Black Start Resource.

(10) If the Black Start Resource successfully passes the second Black Start Resource Availability Test, the QSE representing the Black Start Resource shall resume receipt of the Hourly Standby Fee beginning on the date of the successful Black Start Resource Availability Test.

(11) If the Black Start Resource fails a second Black Start Resource Availability Test within the quarter, it shall immediately be disqualified from providing BSS and shall receive no further compensation under the Black Start Service Agreement. In addition, ERCOT shall claw-back all Hourly Standby Fee payments made to the QSE representing the Black Start Resource since its last successful Black Start Resource Availability Test or its last successful start and operation under normal system conditions, whichever is later. The clawed-back Hourly Standby Fee payments shall be uplifted by ERCOT to Loads on a Load Ratio Share (LRS) basis. ERCOT may, at its sole discretion, consider allowing the Black Start Resource to perform an additional Black Start Resource Availability Test. ERCOT may also, at its sole discretion, seek to procure additional Black Start Resources to replace the disqualified Black Start Resource.

(12) A QSE representing the Black Start Resource shall update its Availability Plan for a Black Start Resource to show zero if the Black Start Resource fails to perform when ERCOT has issued a Dispatch Instruction to come On-Line any time other than for a Blackout. The Black Start Resource shall continue to be shown as unavailable until it successfully starts under normal operations or completes a successful Black Start Resource Availability Test.

(13) If the Black Start Resource fails to perform successfully during an actual Blackout and the Black Start Resource has been declared available, as defined in Section 22, Attachment D, ERCOT shall:

(a) Decertify the Black Start Resource for the remainder of the Black Start Agreement contract term; and

(b) Claw-back 100% of the Hourly Standby Fee paid to the QSE representing the Black Start Resource for all the Operating Days since its last successful Black Start Resource Availability Test or its last successful start and operation under normal system conditions, whichever is later.

8.1.1.2.1.6 Firm Fuel Supply Service Resource Qualification, Testing, and Decertification

(1) Generation Resources that meet the following requirements will be considered qualified to provide Firm Fuel Supply Service (FFSS) and may be selected in the bidding process for FFSS:

(a) Successfully demonstrates dual fuel capability, the ability to establish and burn an alternative onsite stored fuel, and has onsite fuel storage capability in an amount that satisfies the minimum FFSS capability requirements set forth in the FFSS request for proposal (RFP). This minimum alternative fuel storage capability must be demonstrated such that the Firm Fuel Supply Service Resource (FFSSR) has the capability to operate at the awarded MW value for a period defined in the FFSS RFP. A QSE demonstrates this capability by confirming the following in its bid submission form:

(i) The onsite fuel storage for the FFSSR is sufficient to satisfy the requirements established in the Protocols and the FFSS RFP;

(ii) The FFSSR is capable of being dispatched by SCED but does not have to be qualified for any specific Ancillary Service; and

(iii) The FFSSR is able to begin operation using onsite stored alternative fuel within the period defined in the RFP; or

(b) Has an onsite natural gas storage capability in an amount that satisfies the minimum FFSS capability requirements set forth in the FFSS RFP. This minimum alternative onsite storage capability must be demonstrated such that the FFSSR has the capability to operate at the awarded MW value for a period defined in the FFSS RFP. A QSE demonstrates this capability by confirming the following in its bid submission form:

(i) The onsite natural gas fuel storage for the FFSSR is sufficient to satisfy the requirements established in the Protocols and the FFSS RFP;

(ii) The FFSSR is capable of being dispatched by SCED but does not have to be qualified for any specific Ancillary Service; and

(iii) The FFSSR is able to begin operation using onsite stored natural gas fuel within the period defined in the RFP; or

(c) Successfully demonstrates the ability to provide FFSS in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption consistent with qualifying technologies identified by the Public Utility Commission of Texas (PUCT).

(2) A QSE representing an FFSSR must annually demonstrate the FFSSR's capability to use an onsite stored alternative fuel or reserved fuel sources identified in paragraphs (1)(b) and (1)(c) above and sustain its output for 60 minutes at the maximum awarded MW amount. Each QSE representing an FFSSR must annually complete the test or successfully deploy at the maximum awarded MW amount for at least 60 minutes and inform ERCOT by November 1 of each year. The QSE representing the FFSSR shall show the Resource as "ONTEST" in its COP and through its Real-Time telemetry for the duration of the demonstration.

(3) A QSE representing an FFSSR must ensure the full awarded FFSS capability is available by November 15 of each year awarded in the RFP.

(4) A QSE representing an FFSSR shall update its Availability Plan for an FFSSR to show the FFSSR is unavailable if the FFSSR is not available to come On-Line or generate using reserved fuel. The FFSSR shall continue to be shown as unavailable until it can successfully come On-Line using reserved fuel or completes a successful test as described in paragraph (2) above.

(5) If the FFSSR does not reflect that it is available, through its Availability Plan, for the hours for which ERCOT has issued a Watch for winter weather, ERCOT shall claw back and/or withhold the FFSS Standby Fee for 90 days, unless the FFSSR successfully deployed for its entire FFSS award obligation and exhausted emission hours allocated in the RFP for the FFSSR.

(6) If the FFSSR fails to come On-Line or stay On-Line during an FFSS deployment due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Standby Fee for 90 days. A QSE representing an FFSSR may coordinate with ERCOT and seek approval to take the FFSSR Off-Line for no more than four hours to perform critical maintenance associated with consuming the reserved fuel. If the QSE coordinates with ERCOT and receives approval to take the FFSSR unit Off-Line and brings the FFSSR back On-Line within four hours or less, this shall not count as failure to stay On-Line for the purpose of this paragraph.

(7) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment, but fails to telemeter on average an HSL equal to or greater than 95% of the awarded FFSS MW value due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Standby Fee for 90 days, in proportion to the difference between the awarded MW value and the average telemetered HSL over the FFSS deployment period.

(8) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Standby Fee for 90 days, in proportion to the difference between the average MW level instructed by ERCOT over the FFSS deployment period and the corresponding average generation of the FFSSR.

(9) If the FFSSR fails to come On-Line or stay On-Line during an FFSS deployment due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Standby Fee for 15 days.

(10) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to telemeter on average an HSL equal to or greater than 95% of the awarded FFSS MW value due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Standby Fee for 15 days, in proportion to the difference between the awarded MW value and the average telemetered HSL over the FFSS deployment period.

(11) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Standby Fee for 15 days, in proportion to the difference between the average MW level instructed by ERCOT over the FFSS deployment period and the corresponding average generation of the FFSSR.

(12) Notwithstanding paragraphs (5) through (11) above, if the FFSSR is otherwise available but fails to come On-Line or is forced Off-Line due to a transmission system outage or transmission system limitation that would prevent the unit from being deployed to LSL, ERCOT shall not claw back the hourly FFSS Standby Fee. If conditions described in paragraphs (7) and (8) occur for the same deployment period, ERCOT shall only claw back the larger amount calculated in paragraph (7) or (8). If conditions described in paragraphs (10) and (11) occur for the same deployment period, ERCOT shall only claw back the larger amount calculated in paragraph (10) or (11).

[NPRR863 and NPRR1011: Insert applicable portions of Section 8.1.1.2.1.7 below upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.2.1.7 ERCOT Contingency Reserve Service Qualification

(1) ECRS may be provided by:

(a) Unloaded Generation Resources that are On-Line;

(b) Quick Start Generation Resources (QSGRs);

(c) Load Resources that may or may not be controlled by high-set under-frequency relays;

(d) Generation Resources operating in the synchronous condenser fast-response mode; or

(e) Controllable Load Resources.

(2) All Resources qualified to participate in SCED or qualified to telemeter a Resource Status of ONSC are also qualified to provide ECRS when the Resource is On-Line. The amount of ECRS for which the Resource is qualified when On-Line will be limited to the amount of capacity that can be ramped or unloaded within 10 minutes. Off-Line ECRS can only be provided by qualified QSGRs.

(3) The amount of ECRS provided by individual Generation Resources and Load Resources is limited to ten times its telemetered emergency ramp rate. Each Resource providing ECRS must be capable of ramping the Resource's Ancillary Service award for ECRS within ten minutes of the notice to deploy ECRS, and must be able to

maintain the awarded level of deployment for at least one hour. The amount of ECRS on a Generation Resource may be further limited by requirements of the Operating Guides.

(4) A Load Resource must be loaded and capable of unloading the awarded amount of ECRS within ten minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays with settings as specified by the Operating Guides.

(5) Any QSE providing ECRS shall provide communications equipment to receive ERCOT telemetered control deployments of ECRS.

(6) Load Resources providing ECRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay, if applicable.

(7) Each QSE shall ensure that each Resource is able to meet the Resource's obligations to provide the Ancillary Service award. Each Generation Resource and Load Resource providing ECRS when Off-Line as a QSGR with an OFFQS Resource Status, or when not qualified to participate in SCED, must meet additional technical requirements specified in this Section.

(8) A qualification test for each Resource to provide ECRS when Off-Line as a QSGR with an OFFQS Resource Status or as a Load Resource, excluding Controllable Load Resources, is conducted during a continuous eight-hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements:

(a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE it is to provide an amount of ECRS from its Resource to be qualified equal to the amount that the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) Generation Resources desiring qualification to provide ECRS when Off-Line must meet the QSGR qualification criteria outlined under section 8.1.1.2, General Capacity Testing Requirements. ERCOT shall measure the test Resource's response as described under Section 8.1.1.2, General Capacity Testing Requirements, for QSGR. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource's qualification to provide ECRS.

(c) For Load Resources, excluding Controllable Load Resources, desiring qualification to provide ECRS, ERCOT shall deploy ECRS, indicating the MW amount. ERCOT shall measure the test Resource's response as described under Section 8.1.1.4.4.

(d) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing ECRS and shall provide a copy of the certificate to the QSE and the Resource Entity.

8.1.1.3 Ancillary Service Capacity Compliance Criteria

(1) ERCOT shall provide each QSE representing Resources a capacity summary containing as a minimum the same general information required in Section 6.5.7.5, Ancillary Services Capacity Monitor, except specific to only the QSE. The summary shall be updated with calculations every ten seconds by ERCOT and then provided to the QSE every five minutes using the MIS Certified Area.

(2) ERCOT shall continuously measure the overall performance of each QSE in providing each Ancillary Service by comparing the sum of each of the QSE's Resources' telemetered Ancillary Services Resource Responsibility with the QSE's total Ancillary Service responsibility. If the comparison indicates the QSE is not providing sufficient capacity to meet its Ancillary Services responsibility, ERCOT shall notify the QSE via the MIS Certified Area.

(3) The QSE, within ten minutes of receiving the insufficient capacity notification from ERCOT, the QSE must:

(a) If due to a telemetry issue, correct the telemetered Ancillary Services Resource Responsibility to provide sufficient capacity; or

(b) Must provide both appropriate justification for not satisfying their Ancillary Service Obligation and a plan to correct the shortfall that is acceptable with the ERCOT operator. ERCOT shall report non-compliance of Ancillary Service capacity requirements to the Reliability Monitor for review.

(4) A QSE for an ESR that is, was, or will be unable to meet its Ancillary Service Resource Responsibility due to a charging restriction during an EEA Level 3 event shall inform ERCOT of this inability no later than one hour after the end of the EEA Level 3 event. Upon providing such notification, the QSE shall be deemed to have complied with its Ancillary Service Supply Responsibility for a time period following the EEA Level 3 event that is equal to the duration of the suspended charging period during the EEA Level 3 event. However, nothing in this paragraph exempts the QSE from any charge under Section 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide, or any other Settlement consequence due to the Ancillary Service insufficiency.

[NPRR1011, NPRR1040, and NPRR1053: Replace applicable portions of Section 8.1.1.3 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011 or NPRR1053; or upon system implementation for NPRR1040:]

8.1.1.3 Ancillary Service Capacity Compliance Criteria

(1) ERCOT shall provide each QSE representing Resources a capacity summary containing as a minimum the same general information required in Section 6.5.7.5, Ancillary Services Capacity Monitor, except specific to only the QSE. The summary shall be updated with calculations every ten seconds by ERCOT and then provided to the QSE every five minutes using the MIS Certified Area.

(2) ERCOT shall report non-compliance with Ancillary Service capacity requirements to the Reliability Monitor for review. Non-compliance occurs only if a QSE is deficient in its Ancillary Service capacity requirement for more than S% of the five-minute clock intervals that the QSE is carrying an Ancillary Service Supply Responsibility, as calculated for the calendar month in accordance with paragraphs (3) and (4) of this section, or if the QSE is deficient in its Ancillary Service Supply Responsibility, by service type, by more than greater of T% of its Ancillary Service Supply Responsibility or U MW for more than 25 minutes (i.e. five consecutive five-minute clock intervals) in five or more instances within the month. For purposes of this section, a single instance is considered a deficiency of the greater of T% or U MW for more than 25 consecutive minutes, regardless of how long the deficiency persists.

(3) ERCOT shall calculate the Ancillary Service capacity performance metrics under normal operating conditions. ERCOT shall not consider five-minute clock intervals during which any of the following events has occurred:

(a) For a Resource providing Ancillary Service that experiences a Forced Outage, all five-minute clock intervals from the time of the Forced Outage until the next Operating Hour for which the QSE can update its schedule (i.e., within ten minutes before the close of an Adjustment Period). This exemption shall only apply to the first three Outages experienced by any single Resource in the evaluation period. ERCOT shall validate the cause of the Forced Outage through telemetry, however should it not be readily discernable, upon request of ERCOT, the QSE shall provide the following documentation regarding each Forced Derate or Startup Loading Failure:

(i) Its generation log documenting the Forced Outage, Forced Derate or Startup Loading Failure;

(ii) QSE (COP) for the intervals prior to, and after the event; and

(iii) Equipment failure documentation which may include, but not be limited to, Generation Availability Data System (GADS) reports, plant operator logs, work orders, or other applicable information;

(b) For intervals where both the primary and backup Wide Area Network (WAN) connections are inoperative;

(c) For intervals where an Ancillary Service Obligation was traded during the Operating Hour between two QSEs such that one QSE assumed the Ancillary Service Obligation of the other QSE, and the ERCOT Operator was notified of the Ancillary Service Trade as soon as practicable; and

(d) For certain other periods of abnormal operations as determined by ERCOT in its sole discretion.

(4) For each QSE with Resources providing Ancillary Service, ERCOT shall calculate Ancillary Service capacity performance metrics for each month.

(a) Ancillary Service capacity performance is based on the following criteria:

(i) In each five-minute clock interval during which the QSE has an Ancillary Service Supply Responsibility, a QSE may be deficient in its Ancillary Service responsibility, by service type, by no more than the greater of:

(A) T% of its Ancillary Service Supply Responsibility; or

(B) U MW.

(ii) If at the end of the month for which the Ancillary Service capacity performance metric was calculated, the QSE failed to meet its applicable responsibilities as defined in item (i) above during more than S% of the five-minute clock intervals that the QSE was carrying an Ancillary Service Supply Responsibility, ERCOT will report such non-compliance to the Reliability Monitor.

(b) Ancillary Service capacity performance is measured for each service type in five-minute clock intervals based on the difference between Ancillary Service Supply Responsibility and the telemetered responsibility. ERCOT shall measure Ancillary Service capacity performance one time per five-minute clock interval. ERCOT shall not measure Ancillary Service capacity performance during the final 20 seconds of any given five-minute clock interval.

(5) The Ancillary Service capacity performance criteria in paragraphs (2) through (4) above shall be subject to review and approval by the ERCOT Board. The Ancillary Service capacity performance criteria variables S, T, and U shall be posted to the ERCOT website no later than three Business Days after ERCOT Board approval.

8.1.1.3.1 Regulation Service Capacity Monitoring Criteria

(1) ERCOT shall continuously monitor the capacity of each Resource to provide Reg-Up and Reg-Down. When determining this available capacity, ERCOT shall consider for each

Resource with REG status, the actual generation or Load, the Ancillary Service Schedule for Reg-Up and Reg-Down, the HSL, the LSL, ramp rates, any other commitments of Ancillary Service capacity.

[NPRR1011: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall continuously monitor the capacity of each Resource to provide Reg-Up and Reg-Down. When determining this available capacity, ERCOT shall consider for each Resource the Resource Status, the actual generation or Load, the Ancillary Service award for Reg-Up and Reg-Down, the HSL, the LSL, ramp rates, and the Resource's qualification to provide Reg-Up and Reg-Down.

(2) For the Reg-Up and Reg-Down capability provided for a Resource to ERCOT by the Resource's QSE, the amount of Reg-Up or Reg-Down reflected in that capability must be limited to the amount of Reg-Up or Reg-Down that can be sustained by the Resource for at least 15 minutes.

8.1.1.3.2 Responsive Reserve Capacity Monitoring Criteria

(1) ERCOT shall continuously monitor the capacity of each Resource to provide RRS. ERCOT shall consider for each Resource providing RRS capacity, actual generation or Load, the Ancillary Service Schedule for RRS, the HSL, the LSL, and any other commitments of Ancillary Service capacity.

(2) For Load Resources not deployed by a Dispatch Instruction from ERCOT, the amount of RRS capacity provided must be measured as the Load Resource's average Load level in the last five minutes.

(3) A Resource that is capable of providing RRS and that has a Resource Status code of ONRR is considered to be providing frequency responsive capability to the extent that it is not using that capacity to provide energy.

[NPRR1011: Replace Section 8.1.1.3.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

8.1.1.3.2 Responsive Reserve Capacity Monitoring Criteria

(1) ERCOT shall continuously monitor the capacity of each Resource to provide RRS. ERCOT shall consider for each Resource the Resource Status, actual generation or Load, the Ancillary Service award for RRS, the HSL, the LSL, any other Resource-specific RRS capabilities telemetered by the QSE, and the Resource's qualification to provide RRS.

(2) For Load Resources, excluding Controllable Load Resources, that have an RRS award, the amount of RRS capacity provided must be measured as the Load Resource's average Load level in the last five minutes.

(3) A Resource that is capable of providing RRS and that has a Resource Status code of ONSC and an RRS award is considered to be providing frequency responsive capability to the extent that it is not using that capacity to provide energy or other Ancillary Services.

(4) For Resources that are providing RRS and are available for Dispatch by SCED, for the RRS capability provided for a Resource to ERCOT by the Resource's QSE, the amount of RRS reflected in that capability must be limited to the amount of RRS that can be sustained by the Resource for at least 15 minutes. For all other Resources excluding non-Controllable Load Resources providing FFR, for the RRS capability provided for a Resource to ERCOT by the Resource's QSE, the amount of RRS reflected in that capability must be limited to the amount of RRS that can be sustained by the Resource for at least one hour. Any non-Controllable Load Resources qualified to provide FFR, for the FFR capability provided for a Resource to ERCOT by the Resource's QSE, the amount of FFR reflected in that capability must be limited to the amount of FFR that can be sustained by the Resource for at least 15 minutes.

8.1.1.3.3 Non-Spinning Reserve Capacity Monitoring Criteria

(1) ERCOT shall continuously monitor the capacity of each Resource to provide Non-Spin. ERCOT shall consider for each Resource providing Non-Spin capacity, the actual generation, or Load, the Ancillary Service Schedule for Non-Spin, the HSL/Maximum Power Consumption (MPC), the LSL/Low Power Consumption (LPC), ramp rates, and any other commitments of Ancillary Service capacity. ERCOT shall also monitor Non-Spin provided on Resources with OFFNS status.

[NPRR1011: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall continuously monitor the capacity of each Resource to provide Non-Spin. ERCOT shall consider for each Resource the Resource Status, the actual generation or Load, the Ancillary Service award for Non-Spin, the HSL/Maximum Power Consumption (MPC), the LSL/Low Power Consumption (LPC), ramp rates, and the Resource's qualification to provide Non-Spin. ERCOT shall also monitor Non-Spin available from and awarded to qualified Resources with an OFF status.

[NPRR1011 and NPRR1096: Insert applicable portions of paragraph (2) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011; or upon system implementation for NPRR1096:]

(2) For the Non-Spin capability provided for a Resource to ERCOT by the Resource's QSE, the amount of Non-Spin reflected in that capability must be limited to the amount of Non-Spin that can be sustained by the Resource for at least four consecutive hours.

[NPRR863, NPRR1011, and NPRR1096: Insert applicable portions of Section 8.1.1.3.4 below upon system implementation for NPRR863 and NPRR1096; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.3.4 ERCOT Contingency Reserve Service Capacity Monitoring Criteria

(1) ERCOT shall continuously monitor the capacity of each Resource to provide ECRS. ERCOT shall consider for each Resource the Resource Status, the On-Line versus Off-Line status, actual generation or Load, the Ancillary Service award for ECRS, the HSL, the LSL, ramp rates, relay status, and the Resource's qualification to provide ECRS.

(2) For the ECRS capability provided for a Resource to ERCOT by the Resource's QSE, the amount of ECRS reflected in that capability must be limited to the amount of ECRS that can be sustained by the Resource for at least two consecutive hours.

(3) For Load Resources, excluding Controllable Load Resources, that have an ECRS award, the amount of ECRS capacity provided must be measured as the Load Resource's average Load level in the last five minutes.

(4) A Resource that is capable of providing ECRS and that has a Resource Status code of ONSC and an ECRS award is considered to be providing capability to the extent that it is not using that capacity to provide energy or other Ancillary Services.

8.1.1.4 Ancillary Service and Energy Deployment Compliance Criteria

(1) ERCOT shall measure the performance of each Resource in providing Ancillary Services and energy in response to Dispatch Instructions according to the requirements in the sections below. Failure to meet these requirements will be reported to the Reliability Monitor as non-compliance.

8.1.1.4.1 Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance

(1) ERCOT shall limit the deployment of Regulation Service of each QSE for each LFC cycle equal to 125% of the total amount of Regulation Service in the ERCOT System divided by the number of control cycles in five minutes.

(2) For those Resources that do not have a Resource Status of ONDSR or ONDSRREG or Intermittent Renewable Resource (IRR) Groups with no member IRR having a status of ONDSR or ONDSRREG, ERCOT shall compute the GREDP for each Generation Resource that is On-Line and released to SCED Base Point Dispatch Instructions. The GREDP is calculated for each five-minute clock interval as a percentage and in MWs for those Resources with a Resource Status that is not ONDSR or ONDSRREG as follows:

$$\mathbf{GREDP\ (\%) = ABS[((ATG - AEPFR)/(ABP + ARI)) - 1.0] * 100}$$

$$\mathbf{GREDP\ (MW) = ABS(ATG - AEPFR - ABP - ARI)}$$

Where:

ATG = Average Telemetered Generation = the average telemetered generation of the Generation Resource or for the aggregate of the IRRs within an IRR Group for the five-minute clock interval

ARI = Average Regulation Instruction = the amount of regulation that the Generation Resource or IRR Group should have produced based on the LFC deployment signals, calculated by LFC, during each five-minute clock interval

Δfrequency is actual frequency minus 60 Hz

EPFR = Estimated Primary Frequency Response (MW) = if $|\Delta\text{frequency}| \leq$ Governor Dead-Band then EPFR = zero, if not then if Δfrequency > zero, EPFR = (Δfrequency - Governor Dead-Band)/((droop value * 60) – Governor Dead-Band) * HSL * -1, if not then if Δfrequency < zero, EPFR = (Δfrequency + Governor Dead-Band)/((droop value * 60) – Governor Dead-Band) * HSL * -1

AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05 the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval. For Combined Cycle Generation Resources, or Generation Resources that have been approved to telemeter Non-Frequency Responsive Capacity (NFRC), the HSL will be reduced by the telemetered NFRC MW to calculate the EPFR. For Combined Cycle Generation Resources, 5.78% Governor droop shall be used. The Resource-specific calculations will be aggregated for IRR Groups.

ABP = Average Base Point = the time-weighted average of a linearly ramped Base Point or sum of Base Points for IRR Groups, for the five-minute clock interval. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five-minute period. The initial value of the linearly ramped Base Point will be the four-second value of the previous linearly ramped Base Point at the time the new SCED Base Point is received into the ERCOT Energy Management System (EMS). In the event that the SCED Base Point is received after the five-minute ramp period, the linearly ramped Base Point will continue at a constant value equal to the ending four-second value of the five-minute ramp.

(3) For all of a QSE's Resources that have a Resource Status of ONDSR or ONDSRREG ("Dynamically Scheduled Resource (DSR) Portfolio"), ERCOT shall calculate an aggregate GREDP as a percentage and in MWs for those Resources as follows:

$$\mathbf{GREDP\ (\%) = ABS[(\textstyle\sum_{DSR} ATG - \sum_{DSR} DBPOS + Intra\text{-}QSE\ Purchase - Intra\text{-}QSE\ Sale - ARRDDSRLR - ANSDDSRLR - \sum_{DSR} AEPFR) / (ATDSRL + \sum_{DSR} ARI) - 1.0] * 100}$$

$$\mathbf{GREDP\ (MW) = ABS(\textstyle\sum_{DSR} ATG - \sum_{DSR} DBPOS - ATDSRL - ARRDDSRLR - ANSDDSRLR + Intra\text{-}QSE\ Purchase - Intra\text{-}QSE\ Sale - \sum_{DSR} AEPFR - \sum_{DSR} ARI)}$$

Where:

$\sum_{DSR}$ ATG = Sum of Average Telemetered Generation for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval

$\sum_{DSR}$ ARI = Sum of Average Regulation Instruction for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval

ATDSRL = Average Telemetered DSR Load = the average telemetered DSR Load for the QSE for the five-minute clock interval

Intra-QSE Purchase = Energy Trade where the QSE is both the buyer and seller with the flag set to "Purchase"

Intra-QSE Sale = Energy Trade where the QSE is both the buyer and seller with the flag set to "Sale"

$\sum_{DSR}$ AEPFR = Sum of Average Estimated Primary Frequency Response for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval

$\sum_{DSR}$ DBPOS = Sum of the difference between a linearly ramped Base Point minus Output Schedule for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five minute period

ARRDDSRLR = Average Responsive Reserve Deployment DSR Load Resource = the average RRS energy deployment for the five-minute clock interval from Load Resources that are part of the DSR Load

ANSDDSRLR = Average Non-Spin Deployment DSR Load Resource = the average Non-Spin energy deployment for the five-minute clock interval from Load Resources that are part of the DSR Load

(4) For Controllable Load Resources that have a Resource Status of ONRGL or ONCLR, ERCOT shall compute the CLREDP. The CLREDP will be calculated both as a percentage and in MWs as follows:

CLREDP (%) = ABS[((ATPC + AEPFR)/(ABP – ARI)) – 1.0] * 100

CLREDP (MW) = ABS(ATPC – (ABP – AEPFR – ARI))

Where:

ATPC = Average Telemetered Power Consumption = the average telemetered power consumption of the Controllable Load Resource for the five-minute clock interval

ARI = Average Regulation Instruction = the amount of regulation that the Controllable Load Resource should have produced based on the LFC deployment signals, calculated by LFC, during each five-minute clock interval. Reg-Up is considered a positive value for this calculation

AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05, the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval

ABP = Average Base Point = the time-weighted average of a linearly ramped Base Point for the five-minute clock interval. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five-minute period. The initial value of the linearly ramped Base Point will be the four second value of the previous linearly ramped Base Point at the time the new SCED Base Point is received into the ERCOT EMS. In the event that the SCED Base Point is received after the five minute ramp period, the linearly ramped Base Point will continue at a constant value equal to the ending four second value of the five-minute ramp.

(5) ERCOT shall post to the MIS Certified Area for each QSE and for all Generation Resources or Wind-powered Generation Resource (WGR) Groups that are not part of a DSR Portfolio, for the DSR Portfolios, and for all Controllable Load Resources:

(a) The percentage of the monthly five-minute clock intervals during which the Generation Resource or IRR Group was On-Line and released to SCED Base Point Dispatch Instructions;

(b) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR;

(c) The percentage of the monthly five-minute clock intervals during which the Generation Resource, IRR or Controllable Load Resource was providing Regulation Service;

(d) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was less than 2.5 MW;

(e) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was less than 2.5 MW;

(f) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(g) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(h) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was greater than 5.0 MW;

(i) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was greater than 5.0 MW;

(j) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was less than 2.5 MW;

(k) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was less than 2.5 MW;

(l) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(m) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(n) The percent of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was greater than 5.0 MW; and

(o) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was greater than 5.0 MW.

(6) ERCOT shall calculate the GREDP/CLREDP under normal operating conditions. ERCOT shall not consider five-minute clock intervals during which any of the following events has occurred:

- (a) The five-minute intervals within the 20-minute period following an event in which ERCOT has experienced a Forced Outage causing an ERCOT frequency deviation of greater than 0.05 Hz;
- (b) Five-minute clock intervals in which ERCOT has issued Emergency Base Points to the QSE;
- (c) The five-minute clock interval following the Forced Outage of any Resource within the QSE's DSR Portfolio that has a Resource Status of ONDSR or ONDSRREG;
- (d) The five-minute clock intervals following a documented Forced Derate or Startup Loading Failure of a Generation Resource or any member IRR of an IRR Group. Upon request of the Reliability Monitor, the QSE shall provide the following documentation regarding each Forced Derate or Startup Loading Failure:
    - (i) Its generation log documenting the Forced Outage, Forced Derate or Startup Loading Failure;
    - (ii) QSE (COP) for the intervals prior to, and after the event; and
    - (iii) Equipment failure documentation which may include, but not be limited to, Generation Availability Data System (GADS) reports, plant operator logs, work orders, or other applicable information;
- (e) The five-minute clock intervals where the telemetered Resource Status is set to ONTEST such as intervals during Ancillary Service Qualification and Testing as outlined in Section 8.1.1.1, Ancillary Service Qualification and Testing, or the five-minute clock intervals during general capacity testing requirements as outlined in Section 8.1.1.2, General Capacity Testing Requirements;
- (f) The five-minute clock intervals where the telemetered Resource Status is set to STARTUP;
- (g) The five-minute clock intervals where a Generation Resource's ABP is below the average telemetered LSL;
- (h) Certain other periods of abnormal operations as determined by ERCOT in its sole discretion; and
- (i) For a Controllable Load Resource, the five-minute clock intervals in which the computed Base Points are equal to the snapshot of its telemetered power consumption.

(7) All Generation Resources that are not part of a DSR Portfolio, excluding IRRs, and all DSR Portfolios shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) A Generation Resource or DSR Portfolio, excluding an IRR, must have a GREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which GREDP was calculated.

(b) If at the end of the month during which GREDP was calculated a DSR Portfolio has a GREDP less than X% or Y MW for 85% of the five-minute clock intervals, the Reliability Monitor shall, at the request of the QSE with the DSR Portfolio, recalculate GREDP excluding the five-minute clock intervals following the Forced Outage of any Resource within the QSE's DSR Portfolio that has a Resource Status of ONDSR or ONDSRREG continuing until the start of the next Operating Hour for which the QSE is able to adjust. If the Forced Outage of the Resource occurs within ten minutes of the start of the next Operating Hour, then the Reliability Monitor shall not consider any of the five-minute intervals between the time of the Forced Outage and continuing until the start of the second Operating Hour for which the QSE is able to adjust. The requesting QSE shall provide to the Reliability Monitor information validating the Forced Outage including the time of the occurrence of the Forced Outage and documentation of the last submitted COP status prior to the Forced Outage of the Resource for the intervals in dispute.

(c) Additionally, all Generation Resources that are not part of a DSR Portfolio, excluding IRRs, and all DSR Portfolios will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) A Generation Resource or DSR Portfolio, excluding an IRR, must have a GREDP less than the greater of X% or Y MW. A Generation Resource or DSR Portfolio cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and GREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(8) All IRRs and IRR Groups shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output for 95% of the five-minute clock intervals in the month when the Resource or a member IRR of an IRR Group received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR's HSL used by SCED. The expected MW output includes the Resource's Base Point, Regulation Service instructions, and any expected Primary Frequency Response.

(b) Additionally, all IRRs and IRR Groups will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources and IRR Groups must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output. An IRR or IRR Group cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and the Resource or a member of an IRR Group received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR's HSL used by SCED. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(9) All Controllable Load Resources shall meet the following CLREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which CLREDP was calculated.

(b) Additionally, all Controllable Load Resources will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following CLREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following Performance criteria to the Reliability Monitor:

(i) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW. A Controllable Load Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and CLREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(c) For Controllable Load Resources which are providing RRS or Non-Spin, the following intervals will be excluded from these calculations:

(i) Five-minute clock intervals which begin ten minutes or less after a deployment of RRS was deployed to the Resource;

(ii) Five-minute clock intervals which begin ten minutes or less after a recall of RRS when the Resource was deployed for RRS;

(iii) Five-minute clock intervals which begin 30 minutes or less after a deployment of Non-Spin was deployed to the Resource; and

(iv) Five-minute clock intervals which begin 30 minutes or less after a recall of Non-Spin when the Resource was deployed for Non-Spin.

(10) The GREDP/CLREDP performance criteria in paragraphs (7) through (9) above shall be subject to review and approval by TAC. The GREDP/CLREDP performance criteria variables X, Y, and Z shall be posted to the ERCOT website no later than three Business Days after TAC approval.

(11) If at the end of the month during which GREDP was calculated, a non-DSR Resource or a QSE with DSR Resources, has a GREDP less than X% or Y MW for 85% of the five-minute clock intervals, the Reliability Monitor shall, at the request of the QSE, recalculate GREDP excluding the five-minute clock intervals when a Resource is deployed above the unit's ramp rate due to ramp rate sharing between energy and Regulation Service, as described in Section 6.5.7.2, Resource Limit Calculator. The requesting QSE shall provide to the Reliability Monitor information validating the ramp rate violation for the intervals in dispute.

[NPRR863, NPRR879, NPRR963, NPRR965, NPRR1000, NPRR1011, NPRR1014, NPRR1029, NPRR1040, and NPRR1111: Replace applicable portions of Section 8.1.1.4.1 above with the following upon system implementation for NPRR863, NPRR879, NPRR963, NPRR965, NPRR1000, NPRR1014, NPRR1029, or NPRR1040; upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011; upon system implementation of NPRR1000 for NPRR1046; or upon system implementation of SCR819 for NPRR1111:]

8.1.1.4.1 Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics

(1) ERCOT shall compute the GREDP for each Generation Resource that is On-Line and released to SCED for Base Point Dispatch Instructions. The GREDP is calculated for each five-minute clock interval as a percentage and in MWs as follows:

$$\textbf{GREDP (\%) = ABS[((ATG – AEPFR)/(ASP)) – 1.0] * 100}$$

$$\textbf{GREDP (MW) = ABS(ATG – AEPFR – ASP)}$$

Where:

ATG = Average Telemetered Generation = the average telemetered generation of the Generation Resource or for the aggregate of the IRRs within an IRR Group for the five-minute clock interval

Δfrequency is actual frequency minus 60 Hz

EPFR = Estimated Primary Frequency Response (MW) = if │Δfrequency│≤ Governor Dead-Band then EPFR = zero, if not then if Δfrequency > zero, EPFR = (Δfrequency - Governor Dead-Band)/((droop value * 60) – Governor Dead-Band) * HSL * -1, if not then if Δfrequency < zero, EPFR = (Δfrequency + Governor Dead-Band)/((droop value * 60) – Governor Dead-Band) * HSL * -1

AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05 the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval. For Combined Cycle Generation Resources with Non-Frequency Responsive Capacity (NFRC), the HSL to calculate the EPFR will be based on the Resource's high limit of the capacity that is frequency responsive. For Combined Cycle Generation Resources, 5.78% Governor droop shall be used. The Resource-specific calculations will be aggregated for IRR Groups.

ASP = Average Set Point = the time-weighted average of the Resource's Updated Desired Set Point (UDSP) for the five-minute clock interval

(2) For Controllable Load Resources that have a Resource Status of ONL and are acting as a Controllable Load Resource and are not part of an ESR, ERCOT shall compute the CLREDP. The CLREDP will be calculated both as a percentage and in MWs as follows:

CLREDP (%) = ABS[((ATPC + AEPFR)/(ASP)) – 1.0] * 100

CLREDP (MW) = ABS(ATPC – (ASP – AEPFR))

Where:

ATPC = Average Telemetered Power Consumption = the average telemetered power consumption of the Controllable Load Resource for the five-minute clock interval

AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05, the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval

ASP = Average Set Point = the time-weighted average of the Resource's UDSP for the five-minute clock interval

(3) ERCOT shall compute the ESREDP for ESRs. The ESREDP is calculated for each five-minute clock interval as a percentage and in MWs as follows:

ESREDP (%) = ABS[((ATPF – AEPFR)/(ASP)) – 1.0] * 100

ESREDP (MW) = ABS(ATPF – AEPFR – ASP)

Where:

ATPF = Average Telemetered Power Flow = the average telemetered power flow of the Energy Storage Resource for the five-minute clock interval.

ASP = Average Set Point = the time-weighted average of UDSP, for the five-minute clock interval.

Δfrequency is actual frequency minus 60 Hz.

EPFR = Estimated Primary Frequency Response (MW) = If │Δfrequency│≤ Governor Dead-Band then EPFR = zero, if not then if Δfrequency > zero, EPFR = (Δfrequency - Governor Dead-Band)/((droop value * 60) – Governor Dead-Band) * ABS(HSL-LSL) * -1, if not then if Δfrequency < zero, EPFR = (Δfrequency + Governor Dead-Band)/((droop value * 60) – Governor Dead-Band) * ABS(HSL-LSL) * -1.

AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource-specific droop value where 5% droop = 0.05, the Governor Dead-Band (Hz), Resource LSL (MW), and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval.

(4) ERCOT shall post to the MIS Certified Area for each QSE and for all Generation Resources or Wind-powered Generation Resource (WGR) Groups, and for all Controllable Load Resources:

(a) The percentage of the monthly five-minute clock intervals during which the Generation Resource or IRR Group was On-Line and released to SCED Base Point Dispatch Instructions;

(b) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL;

(c) The percentage of the monthly five-minute clock intervals during which the Generation Resource, IRR or Controllable Load Resource was awarded Regulation Service;

(d) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was less than 2.5 MW;

(e) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was less than 2.5 MW;

(f) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(g) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(h) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was greater than 5.0 MW;

(i) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was greater than 5.0 MW;

(j) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was less than 2.5 MW;

(k) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was less than 2.5 MW;

(l) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(m) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(n) The percent of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was greater than 5.0 MW; and

(o) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was greater than 5.0 MW.

(5) ERCOT shall calculate the GREDP/CLREDP/ESREDP under normal operating conditions. ERCOT shall not consider five-minute clock intervals during which any of the following events has occurred:

(a) The five-minute intervals within the 20-minute period following an event in which ERCOT has experienced a Forced Outage causing an ERCOT frequency deviation of greater than 0.05 Hz;

(b) Five-minute clock intervals in which ERCOT has issued Emergency Base Points to the QSE;

(c) The five-minute clock intervals following a documented Forced Derate or Startup Loading Failure of a Generation Resource, ESR, or any member IRR of an IRR Group. Upon request of the Reliability Monitor or ERCOT, the QSE shall provide the following documentation regarding each Forced Derate or Startup Loading Failure:

(i) Its generation log documenting the Forced Outage, Forced Derate or Startup Loading Failure;

(ii) QSE (COP) for the intervals prior to, and after the event; and

(iii) Equipment failure documentation which may include, but not be limited to, Generation Availability Data System (GADS) reports, plant operator logs, work orders, or other applicable information;

(d) The five-minute clock intervals where the telemetered Resource Status is set to ONTEST such as intervals during Ancillary Service Qualification and Testing as outlined in Section 8.1.1.1, Ancillary Service Qualification and Testing, or the five-minute clock intervals during general capacity testing requirements as outlined in Section 8.1.1.2, General Capacity Testing Requirements;

(e) The five-minute clock intervals where the telemetered Resource Status is set to STARTUP;

(f) The five-minute clock intervals where a Generation Resource's ASP is below the average telemetered LSL;

(g) Certain other periods of abnormal operations as determined by ERCOT in its sole discretion;

(h) For a Controllable Load Resource, the five-minute clock intervals in which the computed Base Points are equal to the snapshot of its telemetered power consumption;

(i) For intervals where both the primary and backup Wide Area Network (WAN) connections are inoperative; and

(j) For QSGRs, the five-minute clock intervals in which the QSGR has a telemetered status of SHUTDOWN or telemeters an LSL of zero pursuant to Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process.

(6) All Generation Resources that are not part of an ESR, excluding IRRs, shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) A Generation Resource, excluding an IRR, must have a GREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which GREDP was calculated.

(b) Additionally, all Generation Resources, excluding IRRs, will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) A Generation Resource, excluding an IRR, must have a GREDP less than the greater of X% or Y MW. A Generation Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and GREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(7) All IRRs and IRR Groups shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output for 95% of the five-minute clock intervals in the month when the Resource or a member IRR of an IRR Group was not awarded Ancillary Service and received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR's HSL used by SCED or the IRR was instructed not to exceed its Base Point. The expected MW output includes the Resource's Base Point, Regulation Service instructions, and any expected Primary Frequency Response.

(b) An IRR or IRR Group must have a GREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which the Resource or a member IRR of an IRR Group was awarded Ancillary Service.

(c) Additionally, all IRRs and IRR Groups will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources and IRR Groups must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output. An IRR or IRR Group cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and the Resource or a member of an IRR Group was not awarded Ancillary Service and received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR's HSL used by SCED or the IRR was instructed not to exceed its Base Point. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(ii) An IRR or IRR Group must have a GREDP less than the greater of X% or Y MW when the Resource or a member IRR of an IRR Group was awarded Ancillary Service. An IRR or IRR Group cannot fail this criteria more than three five-minute clock intervals during which EEA was declared. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(8) All Controllable Load Resources that are not part of an ESR shall meet the following CLREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which CLREDP was calculated.

(b) Additionally, all Controllable Load Resources will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following CLREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following Performance criteria to the Reliability Monitor:

(i) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW. A Controllable Load Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and CLREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(c) For Controllable Load Resources which are providing RRS, ECRS, or Non-Spin, the following intervals will be excluded from these calculations:

(i) Five-minute clock intervals which begin ten minutes or less after a deployment of RRS or ECRS was deployed to the Resource;

(ii) Five-minute clock intervals which begin ten minutes or less after a recall of RRS or ECRS when the Resource was deployed for RRS or ECRS;

(iii) Five-minute clock intervals which begin 30 minutes or less after a deployment of Non-Spin was deployed to the Resource; and

(iv) Five-minute clock intervals which begin 30 minutes or less after a recall of Non-Spin when the Resource was deployed for Non-Spin.

(9) All ESRs shall meet the following ESREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) An ESR must have an ESREDP less than the greater of V% or W MW for 85% of the five-minute clock intervals in the month during which ESREDP was calculated.

(b) Additionally, all ESRs will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following ESREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) An ESR must have an ESREDP less than the greater of V% or W MW. An ESR cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and ESREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(10) DC-Coupled Resources shall meet the following ESREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (1) of Section 3.8.7, DC-Coupled Resources, the DC-Coupled Resource must have an ESREDP less than the greater of V% or W MW for 85% of the five-minute clock intervals in the month during which ESREDP for the DC-Coupled Resource was calculated.

(b) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (2) of Section 3.8.7, the DC-Coupled Resource must have an ESREDP less than Z% or the ATG must be less than the expected MW output for 95% of the five-minute clock intervals in the month when the DC-Coupled Resource received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the DC-Coupled Resource’s HSL used by SCED or the IRR was instructed not to exceed its Base Point. The expected MW output includes the Resource’s Base Point and any expected Primary Frequency Response.

(c) Additionally, all DC-Coupled Resources will be measured for performance during intervals in which ERCOT has declared an EEA. These Resources must meet the following ESREDP criteria for the time window that includes all five-minute clock intervals during which the EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (1) of Section 3.8.7, the DC-Coupled Resource must have an ESREDP less than the greater of V% or W MW. A DC-Coupled Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and ESREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(ii) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (2) of Section 3.8.7, the DC-Coupled Resource must have a ESREDP less than Z% or the ATG must be less than the expected MW output. A DC-Coupled Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and the DC-Coupled Resource received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the DC-Coupled Resource's HSL used by SCED or the IRR was instructed not to exceed its Base Point. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(11) The GREDP/CLREDP/ESREDP performance criteria in paragraphs (6) through (10) above shall be subject to review and approval by TAC. The GREDP/CLREDP/ESREDP performance criteria variables V, W, X, Y, and Z shall be posted to the ERCOT website no later than three Business Days after TAC approval.

(12) If at the end of the month during which GREDP was calculated, a Resource has a GREDP less than X% or Y MW for 85% of the five-minute clock intervals, the Reliability Monitor shall, at the request of the QSE, recalculate GREDP excluding the five-minute clock intervals when a Resource is deployed above the unit's ramp rate due to ramp rate sharing between energy and Regulation Service. The requesting QSE shall provide to the Reliability Monitor information validating the ramp rate violation for the intervals in dispute.

8.1.1.4.2 Responsive Reserve Energy Deployment Criteria

(1) Each QSE providing RRS shall so indicate by appropriate entries in the Resource's Ancillary Service Schedule and the Ancillary Service Resource Responsibility providing that service. When manually deployed as specified in Nodal Operating Guide Section 4.8, Responsive Reserve Service During Scarcity Conditions, SCED shall adjust the Generation Resource's Base Point for any requested RRS energy in the next cycle of SCED as specified in Section 6.5.7.6.2.2, Deployment of Responsive Reserve Service. For Controllable Load Resources, the QSE shall control its Resources to operate to the Resource's Scheduled Power Consumption minus any Ancillary Service deployments. Control performance during periods in which RRS has been self-deployed shall be based

on the requirements below and failure to meet any one of these requirements may be reported to the Reliability Monitor as non-compliance:

(a) Within one minute following a deployment instruction, the QSE must update the telemetered Ancillary Service Schedule for RRS for Generation Resources and Load Resources to reflect the deployment amount. The difference between the sum of the QSE's Resource RRS schedules and the sum of the QSE's Resource RRS responsibilities must be equal to the QSE's total RRS deployment instruction, excluding the deployment to Load Resources which are not Controllable Load Resources.

(b) A QSE providing RRS must reserve sufficient Primary Frequency Response capable capacity on each Generation Resource with a RRS responsibility or must reserve sufficient capacity capable of FFR to supply the full amount of RRS scheduled for that Resource. The QSE shall not use NFRC, such as power augmentation capacity on a Generation Resource, to provide RRS.

(c) ERCOT shall evaluate the Primary Frequency Response of all RRS providers as calculated in Nodal Operating Guide Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response.

(2) For all Frequency Measurable Events (FMEs), ERCOT shall use the recorded data for each two-second scan rate value of real power output for each Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), Resource capable of FFR providing RRS, and Controllable Load Resource. ERCOT shall use the recorded MW data beginning one minute before the start of the frequency excursion event until ten minutes after the start of the frequency excursion event. Satisfactory performance for those Resources with a RRS responsibility must be measured by comparing actual Primary Frequency Response to the expected Primary Frequency Response as required in the Operating Guides.

(3) ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Generation Resources, SOTGs, SOTSGs, Resources capable of FFR, and Controllable Load Resources with RRS responsibilities using the methodology specified in the Operating Guides. ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Controllable Load Resources, relay response for Loads and Generation Resources operating in the synchronous condenser fast-response mode providing RRS at the frequency specified in paragraph (3)(b) of Section 3.18, Resource Limits in Providing Ancillary Service.

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

(i) The QSE's Responsibility for RRS from non-Controllable Load Resources; or

(ii) The requested MW deployment.

The QSE's portfolio shall maintain this response until recalled or the Resource's obligation to provide RRS expires. The combination of the QSE's RRS responsibility and additional available capacity shall not exceed 150% of the sum of the QSE's Ancillary Service Resource Responsibility for RRS from non-Controllable Load Resources. Any additional available capacity from Load Resources other than Controllable Load Resources shall be deployed concurrently with RRS.

(5) For Load Resources, excluding Controllable Load Resources, associated with a QSE that does not successfully deploy as defined under this Section, ERCOT shall evaluate, identify and investigate each Load Resource that contributed to such failure, in order to determine failure under paragraph (9) of Section 8.1.1.1, Ancillary Service Qualification and Testing.

(6) A Load Resource providing RRS excluding Controllable Load Resources must return to at least 95% of its Ancillary Service Resource Responsibility for RRS within three hours following a recall instruction unless replaced by another Resource as described below. However, the Load Resource should attempt to return to at least 95% of its Ancillary Service Resource Responsibility for RRS as soon as practical considering process constraints. For a Load Resource that is not a Controllable Load Resource that is unable to return to its Ancillary Service Resource Responsibility within three hours of recall instruction, its QSE may replace the quantity of deficient RRS capacity within that same three hours using other Generation Resources or other Load Resources not previously committed to provide RRS.

(7) During periods when the Load level of a Load Resource (excluding Controllable Load Resources) has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource's actual Load response from its Baseline. "Baseline" capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

[NPRR863, NPRR995, and NPRR1011: Replace applicable portions of Section 8.1.1.4.2 above with the following upon system implementation for NPRR863 and NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.4.2 Responsive Reserve Energy Deployment Criteria

(1) Control performance during periods in which RRS has been self-deployed shall be based on the requirements below and failure to meet any one of these requirements may be reported to the Reliability Monitor as non-compliance:

(a) A QSE providing RRS must reserve sufficient Primary Frequency Response capable capacity on each Generation Resource with a RRS award or must reserve sufficient capacity capable of FFR to supply the full amount of RRS awarded to that Resource. The QSE shall not use non-FRC, such as power augmentation capacity on a Generation Resource, to provide RRS.

(b) ERCOT shall evaluate the Primary Frequency Response of all RRS providers as calculated in Nodal Operating Guide Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response.

(2) For all Frequency Measurable Events (FMEs), ERCOT shall use the recorded data for each two-second scan rate value of real power output for each Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), Settlement Only Transmission Energy Storage System (SOTESS), Resource capable of FFR providing RRS, and Controllable Load Resource. ERCOT shall use the recorded MW data beginning one minute before the start of the frequency excursion event until ten minutes after the start of the frequency excursion event. Satisfactory performance for those Resources with an RRS award must be measured by comparing actual Primary Frequency Response to the expected Primary Frequency Response as required in the Operating Guides.

(3) ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Generation Resources, SOTGs, SOTSGs, SOTESSs, Resources capable of FFR, and Controllable Load Resources with RRS responsibilities using the methodology specified in the Operating Guides. ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Controllable Load Resources, relay response for Loads and Generation Resources operating in the synchronous condenser fast-response mode providing RRS at the frequency specified in paragraph (3)(b) of Section 3.18, Resource Limits in Providing Ancillary Service.

(4) For Resources providing FFR, once the FFR is deployed, the Resource must stay deployed for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurs first. A Load Resource that is controlled by a high-set under-frequency relay and is providing FFR may only withdraw energy from the grid after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, or if instructed to do so by ERCOT.

(5) For a Resource providing RRS with a Resource Status of ONSC, once the RRS is deployed, the Resource must maintain the response until recalled by ERCOT.

(6) For a Load Resource that is controlled by a high-set under-frequency relay and is providing RRS, once the RRS is deployed, the Resource must maintain the response to the deployment until recalled by ERCOT.

(7) For QSEs with Load Resources, excluding Controllable Load Resources, ten minutes following deployment instruction the sum of the QSE's Load Resource response shall

not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:

(i) The QSE’s award for RRS from non-Controllable Load Resources; or

(ii) The requested MW deployment.

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

(8) For Load Resources, excluding Controllable Load Resources, associated with a QSE that does not successfully deploy as defined under this Section, ERCOT shall evaluate, identify and investigate each Load Resource that contributed to such failure, in order to determine failure under paragraph (9) of Section 8.1.1.1, Ancillary Service Qualification and Testing.

(9) For a QSE self-providing RRS on Load Resources, excluding Controllable Load Resources that have been deployed for RRS, the QSE may move the self-provided amount to another Load Resource, while maintaining the deployment instructions on the previously deployed Load Resource, if:

(a) The Load Resource to which the RRS is to be moved is not a Controllable Load Resource and has not been deployed for RRS; and

(b) The self-provided amount of RRS is within the QSE’s portfolio.

(10) During periods when the Load level of a Load Resource (excluding Controllable Load Resources) has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource’s actual Load response from its Baseline. “Baseline” capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

8.1.1.4.3 Non-Spinning Reserve Service Energy Deployment Criteria

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

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

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

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

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

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

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

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

(d) Controllable Load Resources must be available to SCED, and within 25 minutes following a deployment instruction must have a Real-Time Market (RTM) Energy Bid and the telemetered net real power consumption must be greater than or equal to the Resource's telemetered LPC.

[NPRR1131: Delete paragraph (d) above upon system implementation and renumber accordingly.]

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

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

(ii) The requested MW deployment.

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

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

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

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

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

8.1.1.4.3 Non-Spinning Reserve Service Energy Deployment Criteria

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

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

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

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

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

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

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

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

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

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

(ii) The requested MW deployment.

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

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

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

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

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

disqualified Load Resource successfully passes qualification test as specified in Section 8.1.1.1, Ancillary Service Qualification and Testing.

[NPRR863 and NPRR1011: Insert applicable portions of Section 8.1.1.4.4 below upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.4.4 ERCOT Contingency Reserve Service Energy Deployment Criteria

(1) Control performance during periods in which ERCOT has manually deployed ECRS shall be based on the requirements below and failure to meet any one of these requirements shall be reported to the Reliability Monitor as non-compliance:

(a) For a Resource providing ECRS with a Resource Status of ONSC, once the ECRS is deployed, the Resource must maintain the response until recalled by ERCOT.

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

(i) The QSE's awards for ECRS from non-Controllable Load Resources; or

(ii) The requested MW deployment.

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

(c) For Load Resources, excluding Controllable Load Resources, associated with a QSE that does not successfully deploy as defined under this Section, ERCOT shall evaluate, identify and investigate each Load Resource that contributed to such failure, in order to determine failure under paragraph (9) of Section 8.1.1.1, Ancillary Service Qualification and Testing.

(d) For a QSE self-providing ECRS on a Load Resource, excluding Controllable Load Resources that have been deployed, the QSE may move the self-provided amount to another Load Resource, while maintaining the deployment instructions on the previously deployed Load Resources, if:

(i) The Load Resource to which the ECRS is to be moved is not a Controllable Load Resource and has not been deployed for ECRS; and

(ii) The self-provided amount of ECRS is within the QSE's portfolio.

(e) During periods when the Load level of a Load Resource (excluding Controllable Load Resources) has been affected by a Dispatch Instruction from

ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource's actual Load response from its Baseline. "Baseline" capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

8.1.2 Current Operating Plan (COP) Performance Requirements

(1) Each QSE representing a Resource must submit a COP in accordance with Section 3.9, Current Operating Plan (COP).

(2) For each QSE, ERCOT shall post for each month the number, by Operating Hour, of valid COP failures to meet the provisions of paragraphs (3) and (4) of Section 3.9.2, Current Operating Plan Validation, for Ancillary Service Resource Responsibilities contained in the QSE's COP used for the DRUC and each HRUC during the Operating Day. QSEs shall have no more than three hours during an Operating Day or 74 hours during a month that contains COP Ancillary Service Resource Responsibility validation failures.

[NPRR1011: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(3) For each QSE, ERCOT shall post for each month the number of Operating Hours during which a Reliability Unit Commitment (RUC)-committed QSE Resource, not Off-Line as the result of a Forced Outage, failed to be On-Line and released to SCED for deployment within the first 15 minutes of the RUC-Commitment Hour. QSEs shall have no more than three hours during an Operating Day and no more than 74 hours during a month that contains one or more of these events.

(4) ERCOT shall post for each QSE for each month the number of Operating Hours during which a RUC-committed Resource with a cold start time of one hour or less, not Off-Line as the result of a Forced Outage, failed to be On-Line and released to SCED (has reached its physical LSL) within its cold start time by the start of the Operating Hour for which it was RUC-committed. Any Resource with more than one occurrence during a month whereby the cold start time is not met shall be removed from special consideration pursuant to paragraph (7) of Section 5.5.2, Reliability Unit Commitment (RUC) Process, for a period of 90 days, beginning with the next Operating Day following the second occurrence within a month.

8.1.3 Emergency Response Service Performance and Testing

(1) Performance metrics for Emergency Response Service (ERS) event performance, availability, and testing are detailed in this section for both ERS Loads and ERS Generators.

8.1.3.1 Performance Criteria for Emergency Response Service Resources

(1) ERS Resources' compliance will be based on their performance during ERS deployment event(s), their performance in ERS testing, and their availability during an ERS Contract Period. The performance evaluation has three purposes:

(a) To provide the QSE a basis for determining the ERS Resource's offer capacity;

(b) To provide the basis for ERCOT to determine the ERS Resource's availability during its committed hours in an ERS Contract Period; and

(c) To measure and verify the ERS Resource's performance, as compared to its contracted capacity, during an ERS deployment event or test.

8.1.3.1.1 Baselines for Emergency Response Service Loads

(1) As part of the ERS procurement process, ERCOT shall notify QSEs of an ERS Load's eligibility to be evaluated on one or more of the following baselines, which are developed and administered by ERCOT consistent with the North American Energy Standards Board (NAESB) Practice Standards:

(a) The "ERS Default Baseline" requires an ERS Load to reduce its Load by its contracted amount, and is a method of estimating the electricity that would have been consumed by an ERS Load in the absence of an ERS deployment event;

(b) The "ERS Alternate Baseline" requires an ERS Load to reduce Load to a contracted level of electricity Demand (its maximum base load) in an ERS deployment event.

(2) ERS Default Baseline:

(a) As part of its Resource identification process, ERCOT will determine if each ERS Load can qualify under a default baseline methodology. A default baseline methodology is designed to predict the interval Load based on variables which may include historic Load data, weather, time of day and other relevant calendar information. ERCOT may use other data variables in a default baseline methodology at ERCOT's sole discretion, if ERCOT determines the additional data will enhance the accuracy of the default baseline. Development of a default baseline for each ERS Load will be consistent with practices described in the document entitled "Demand Response Baseline Methodologies" posted on the ERCOT website.

(b) For aggregated ERS Loads, ERCOT may develop either a single baseline model at the aggregate level or multiple baseline models for individual sites and/or subsets of sites within the aggregation. If ERCOT develops the model at the site and/or subset level, ERCOT shall establish the default baseline for the aggregated ERS Load by summing the baselines of the individual sites and/or subsets of sites in the aggregation. ERCOT shall verify the performance at the ERS Load level.

(c) ERCOT will develop a default baseline for an ERS Load by analyzing historic 15-minute interval usage data.

(d) If ERCOT determines that an ERS Load qualifies for a default baseline, ERCOT shall provide default baseline analysis results for the ERS Load to the QSE representing that ERS Resource.

(3) ERS Alternate Baseline:

(a) ERCOT may assign an ERS Load to an alternate baseline formula for one of the following reasons:

(i) ERCOT determines that the ERS Load does not have sufficient predictability for a default baseline;

(ii) The QSE requests an alternate baseline for the ERS Load; or

(iii) ERCOT has insufficient historical meter data available at the time of baseline evaluation to accurately model the ERS Load.

(b) If, following ERS procurement, ERCOT determines that sufficient historical data is available and the ERS Load has sufficient predictability for a default baseline, ERCOT with the QSE's consent may reassign the ERS Load to a default baseline, notify the QSE of the reassignment, and calculate performance for the ERS Contract Period accordingly.

(c) Under the alternate baseline formula, ERCOT shall calculate an ERS Load's average (mean) Load (MWh) over the most recent available 12-month period, with an emphasis on the months corresponding to the upcoming ERS Standard Contract Term. ERCOT will validate the MW capacity offer for each ERS Load for the applicable ERS Time Period, based upon the difference between this average Load calculation (MWh) and the ERS Load's declared maximum base Load (MWh). In selecting an ERS Load with an alternate baseline, ERCOT may award the lesser of the MW offer or the MW capacity validated by ERCOT.

(4) ERS Weather-Sensitive Load:

(a) ERCOT shall assign a residential Weather-Sensitive ERS Load to either the regression baseline performance evaluation methodology or the control group baseline performance evaluation methodology. Both methodologies are described in the document entitled "Demand Response Baseline Methodologies" posted to the ERCOT website. The control group baseline performance evaluation methodology shall only be available to ERS Loads consisting entirely of residential sites.

(i) At least nine months of interval data for all sites within an ERS Load are required for the Load to be eligible for the regression baseline evaluation methodology. If one or more sites lack sufficient interval data, the ERS Load will either be evaluated using the control group baseline performance evaluation methodology or will be disqualified from participation as an ERS Load.

(ii) Sites in an ERS Load assigned to the control group baseline are required to have fully functional interval metering in place at the start of an ERS Standard Contract Term, but are not required to have historical meter data prior to that time.

(iii) If ERCOT determines that the residential ERS Load may be assigned to either baseline methodology, the QSE may select its preferred option.

(b) If the ERS Load consists of non-residential sites, the ERS Load must qualify for at least one ERS default baseline methodology, as described in paragraph (2) above.

(c) For an ERS Load assigned to the control group baseline, ERCOT will divide the aggregation into multiple randomly assigned numbered groups for purposes of testing and deployment event Dispatch, and one of these groups will be designated as the control group, to be held out of the test or event, at time of Dispatch. All remaining ERS Loads will participate and be evaluated in each test or event relative to the control group. ERCOT will strive to minimize control group size while preserving the ability to achieve accurate Demand response measurement and verification. The number of groups, group size and group designations are subject to change if the QSE adjusts the population of the ERS Load during the ERS Standard Contract Term, as described in paragraph (15) of Section 3.14.3.1, Emergency Response Service Procurement.

(5) All ESI IDs within an aggregated ERS Load must be on the same baseline methodology (either the ERS Default Baseline, or the ERS Alternate Baseline).

8.1.3.1.2 Performance Evaluation for Emergency Response Service Generators

(1) ERCOT shall evaluate the event performance of an ERS Generator by measuring net injection of energy to the ERCOT System using data from metering as described in

paragraph (5)(a) of Section 3.14.3.3, Emergency Response Service Provision and Technical Requirements.

(2) A Non-Weather-Sensitive ERS Load will be classified as co-located with an ERS Generator if each site in the ERS Load is physically located with a site in the ERS Generator, and if both the ERS Generator and the ERS Load are represented by the same QSE and are participating in the same ERS service type and Time Periods. If separate offers are received from different QSEs, both offers will be rejected. A Weather-Sensitive ERS Load is not eligible to be classified as co-located with an ERS Generator.

(3) If an ERS Generator is co-located with an ERS Load the following shall apply:

(a) If a default baseline has been selected by a QSE for ERS performance evaluation for an ERS Load that is co-located with an ERS Generator, event and test performance of the ERS Generator and ERS Load shall be evaluated jointly using interval data from the Transmission and/or Distribution Service Provider (TDSP) installed metering. The joint performance will be attributed to both the ERS Load and ERS Generator.

(b) The self-serve capacity used to calculate availability in each ERS Time Period for the ERS Generator shall be deemed to be the lesser of the self-serve capacity specified on the offer or the peak Load of the ERS Load during that ERS Time Period over the 12 months preceding the beginning of the ERS Standard Contract Term.

(c) If the co-located ERS Load is assigned to the ERS Alternate Baseline, the performance during an ERS deployment event or ERCOT test shall be evaluated using one of two methods selected by the QSE:

(i) The QSE may elect to have the performance of the ERS Generator and ERS Load evaluated separately. In this case:

(A) All site Load must participate in the ERS Load and ERCOT shall calculate interval-by-interval values for the Load of each site in the ERS Load by adding the MWh output measured by the QSE-installed metering on the generator(s) at the site to the MWh consumption measured by the TDSP metering and by subtracting the MWh export from the site, as measured by the TDSP metering. The performance of the ERS Load shall be evaluated using the ERCOT calculated values of the site Load.

(B) The ERS Generator shall be evaluated using the interval data measured by the metering on the output of the generator(s) as required by paragraph (5)(a) of Section 3.14.3.3. For purposes of determining ERS Generator performance, the injection capacity in each ERS Time Period for the ERS Generator shall be deemed to be the sum of self-serve capacity and injection capacity submitted on the offer for that ERS Time Period, and the self-serve capacity used to measure performance for that ERS Time Period shall be deemed to be zero.

(ii) The QSE may elect to have the performance of the ERS Generator and ERS Load evaluated jointly. In this case, ERCOT shall use the TDSP metering installed for the performance evaluation.

(A) If ERCOT determines that one of its established default baseline types accurately represents the ERS Load's Demand response contribution, the contribution of the ERS Load to the joint performance shall be based on that response.

(B) If ERCOT determines that none of its established default baseline types accurately represents the ERS Load's Demand response contribution, the contribution of the ERS Load to the joint performance shall be deemed to be the product of the ERS Load's obligation for the interval and the ERS Interval Performance Factor ($EIPF_i$) as computed in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources.

(C) The joint performance will be attributed to both the ERS Load and ERS Generator.

(4) If the ERS Generator is not co-located with an ERS Load the following shall apply:

(a) For purposes of determining ERS performance, the self-serve capacity used to measure performance in each time period for the ERS Generator shall be deemed to be zero and the injection capacity used to measure performance shall be equal to the amount submitted on the offer.

(b) The ERS Generator shall have its performance based on its metered output to the ERCOT System as measured by the TDSP metering.

8.1.3.1.3 Availability Criteria for Emergency Response Service Resources

(1) No later than 45 days after the end of an ERS Standard Contract Term, ERCOT shall provide each QSE representing ERS Resources with an availability report for its ERS portfolio for each ERS service type. The report shall contain:

(a) For each ERS Time Period and each ERS Contract Period in the ERS Standard Contract Term, the ERS availability factor (ERSAF) for each ERS Resource in the QSE's ERS portfolio, as described in Sections 8.1.3.1.3.1, Time Period Availability Calculations for Emergency Response Service Loads, and 8.1.3.1.3.2, Time Period Availability Calculations for Emergency Response Service Generators.

(b) For each ERS Contract Period in the ERS Standard Contract Term, the QSE’s portfolio-level availability factor, as described in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities.

(c) The QSE’s portfolio-level availability factor for the Standard Contract Term, as described in Section 8.1.3.3.

8.1.3.1.3.1 Time Period Availability Calculations for Emergency Response Service Loads

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

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

(i) The interval Load of the ERS Load was less than 95% of its contracted ERS MW capacity; or

(ii) Required metered interval data was not provided to ERCOT by the time ERCOT calculated availability for one or more sites in the ERS Resource.

(b) Otherwise, the ERS Load will be considered available for that 15-minute interval. The ERSAF will be the ratio of the number of 15-minute intervals the ERS Load was available during the ERS Time Period divided by the total number of 15-minute intervals in the ERS Time Period.

(c) Notwithstanding the foregoing, in determining the ERSAF, ERCOT will exclude from the calculation the following contracted intervals:

(i) Any 15-minute interval in which the ERS Load was deployed during an ERS deployment event or unannounced test, including intervals that begin during the ten-hour ERS recovery period following the issuance of the recall instruction; and

(ii) Any 15-minute interval following an ERS deployment resulting in exhaustion of the ERS Load’s obligation in an ERS Contract Period.

(2) For an ERS Load assigned to the alternate baseline, ERCOT will calculate its ERSAF for an ERS Time Period using the following formula:

$$\mathbf{ERSAF}_{qce(tp)d} = \mathbf{MIN}\ (1, (\mathbf{AV}_{qce(tp)d} / (\mathbf{OFFERMW}_{qce(tp)d})))$$

The above variables are defined as follows:

Variable	Unit	Description
AV $qce(tp)d$	MW	Average MW Load, calculated as the average of the actual interval MW values or the MW values determined in accordance with paragraphs (a), (b), and (c) below, per 15-minute interval for an ERS Load in a contracted ERS Time Period per ERS service type *d*, excluding declared maximum base Load.
OFFERMW $qce(tp)d$	MW	An ERS Load's contracted capacity for an ERS Time Period, per ERS service type *d*, applicable to either competitively procured or self-provided ERS.
ERSAF $qce(tp)d$	None	Availability factor for an ERS Load for an ERS Time Period per ERS service type *d*.
q	None	A QSE.
c	None	ERS Contract Period.
e	None	An ERS Load.
tp	None	ERS Time Period.
d	None	ERS service type (Weather-Sensitive ERS-10, Non-Weather-Sensitive ERS-10, Weather -Sensitive ERS-30, or Non-Weather-Sensitive ERS-30).

(a) If the ERS Load is co-located with an ERS Generator and the QSE has opted for separate evaluation, its Load, for purposes of availability calculations, shall be determined as specified in paragraph (3)(c) of Section 8.1.3.1.2, Performance Evaluation for Emergency Response Service Generators.

(b) For purposes of calculating availability, the interval MW value will be deemed to be equal to the declared maximum base Load if the following condition is met:

(i) Required metered interval data was not provided to ERCOT by the time ERCOT calculated availability for one or more sites in the ERS Resource.

(c) For purposes of calculating availability, ERCOT shall exclude from the average any 15-minute interval meeting one or more of the following descriptions:

(i) Any 15-minute interval in which the ERS Load was deployed during an ERS deployment event or unannounced test, including intervals that begin during the ten-hour ERS recovery period following the issuance of the recall instruction; or

(ii) Any 15-minute interval following the ERS deployment resulting in exhaustion of the ERS Load's obligation in an ERS Contract Period.

(3) A Weather-Sensitive ERS Load shall always have its availability factor for an ERS Contract Period set to 1.0 and its availability settlement weighting factor (ERSAFWT) set to zero.

8.1.3.1.3.2 Time Period Availability Calculations for Emergency Response Service Generators

(1) ERCOT shall evaluate the availability of an ERS Generator by using data from 15-minute interval metering dedicated to the ERS Generator.

(2) ERCOT will calculate an ERSAF using interval meter readings for an ERS Generator for each committed ERS Time Period as the ratio of the number of 15-minute intervals the ERS Generator was available in the ERS Time Period divided by the total number of obligated 15-minute intervals in the ERS Time Period. ERS Generators are considered available for any 15-minute interval except the following:

(a) An ERS Generator that is not co-located with an ERS Load will be considered unavailable for all 15-minute intervals that are part of an unsuccessful unannounced ERCOT test or event, as well as any subsequent intervals following the end of the test or event up to the interval immediately preceding the first full 15-minute interval for which the ERS Generator injects energy to the ERCOT System at a level greater than or equal to the sum of its injection capacity and obligation at the time of the test or event. The success or lack of success of an unannounced ERCOT test or event is determined by the criteria specified in Section 8.1.3.2, Testing of Emergency Response Service Resources.

(b) An ERS Generator that is co-located with an ERS Load and is being separately evaluated from the ERS Load will be considered unavailable for all 15-minute intervals that are part of an unsuccessful unannounced ERCOT test or event, as well as any subsequent intervals following the end of the test up to the interval immediately preceding the first full 15-minute interval for which the ERS Generator's output energy is greater than or equal to the sum of its injection capacity and obligation at the time of the test or event. The success or lack of success of an unannounced ERCOT test or event is determined by the criteria specified in Section 8.1.3.2.

(c) An ERS Generator that is co-located with an ERS Load and is being evaluated jointly with the ERS Load will be considered unavailable for all 15-minute intervals that are part of an unsuccessful unannounced ERCOT test or event, as well as any subsequent intervals following the end of the test up to the interval immediately preceding the first full 15-minute interval for which the combined performance of the ERS Load and ERS Generator is greater than or equal to the combined obligation at the time of the test or event. The success or lack of success of an unannounced ERCOT test or event is determined by the criteria specified in Section 8.1.3.2.

(d) An ERS Generator will be considered unavailable during any 15-minute interval of an obligated ERS Time Period in which any of the following conditions are present:

(i) The ERS Generator output is greater than the sum of its self-serve capacity and its declared injection capacity for the ERS Time Period;

(ii) The export to the grid for the ERS Generator is greater than the injection capacity for the ERS Time Period; or

(iii) Required metered interval data was not provided to ERCOT by the time ERCOT calculated availability for one or more sites in the ERS Resource.

(e) ERCOT shall exclude any 15-minute intervals meeting one or more of the following descriptions from the availability:

(i) Any 15-minute interval in which the ERS Generator was deployed during an ERS deployment event or unannounced test, including intervals that begin during the ten-hour ERS recovery period following the issuance of the recall instruction; and

(ii) 15-minute intervals during a successfully completed ERCOT unannounced test of the ERS Generator including intervals that begin during the ten-hour ERS recovery period.

8.1.3.1.3.3 Contract Period Availability Calculations for Emergency Response Service Resources

(1) ERCOT shall compute a single time- and capacity-weighted availability factor (ERSAFCOMB) for each ERS Resource for an ERS Contract Period from the ERS Time Period ERSAFs calculated in Sections 8.1.3.1.1, Baselines for Emergency Response Service Loads, and 8.1.3.1.3.2, Time Period Availability Calculations for Emergency Response Service Generators, as follows:

$$\textbf{If HOURS}_{\textbf{\textit{qce(tp)d}}} \textbf{ = 0, ERSAFCOMB}_{\textbf{\textit{qced}}} \textbf{ = 1}$$

Otherwise

$$\textbf{ERSAFCOMB}_{\textbf{\textit{qced}}} = \sum_{tp} (\textbf{HOURS}_{qce(tp)d} * \textbf{OFFERMW}_{\textbf{\textit{qce(tp)d}}} * \textbf{ERSAF}_{\textbf{\textit{qce(tp)d}}}) / \sum_{tp} (\textbf{HOURS}_{\textbf{\textit{qce(tp)d}}} * \textbf{OFFERMW}_{qce(tp)d})$$

The above variables are defined as follows:

Variable	Unit	Description
ERSAFCOMB $_{qced}$	None	Time- and capacity-weighted availability factor for an ERS Contract Period per ERS service type *d*.

$\text{HOURS}_{qce(tp)d}$	Hours	The number of hours an ERS Resource is obligated in an ERS Time Period per ERS service type *d* minus any hours in that Time Period excluded for purposes of computing availability.
$\text{OFFERMW}_{qce(tp)d}$	MWh	The ERS Resource's contracted capacity for that time period per ERS service type *d* expressed in units of MWh.
$\text{ERSAF}_{qce(tp)d}$	None	Availability factor for an ERS Resource for an ERS Time Period and per ERS service type *d*.
q	None	A QSE.
c	None	ERS Contract Period.
e	None	Individual ERS Resource.
tp	None	ERS Time Period.
d	None	ERS service type (Weather-Sensitive ERS-10, Non-Weather-Sensitive ERS-10, Weather-Sensitive ERS-30, or Non-Weather-Sensitive ERS-30).

(2) In an ERS Contract Period with no ERS deployment events, the ERSAFWT for all ERS Resources shall be set to 1.0.

(3) In an ERS Contract Period with one or more ERS deployment events and in which no ERS Resource's ERS obligation is exhausted, the ERSAFWT for deployed ERS Resources shall be set to 0.25 and the ERSAFWT for all undeployed ERS Resources shall be set to 1.0.

(4) If, pursuant to Section 3.14.3.1, Emergency Response Service Procurement, an ERS Contract Period is shorter than the associated ERS Standard Contract Term the following shall apply:

(a) For all deployed ERS Resources, the ERSAFWT of the exhausted or discontinued ERS Resource shall be set to 0.25 × ERSAFHRS_{qced} with ERSAFHRS_{qced} determined as calculated in paragraph (c) below.

(b) For all ERS Resources with no deployments during the ERS Contract Period, ERSAFWT shall be set to 1.0.

(c) ERSAFHRS_{qced} for the ERS Contract Period shall be calculated using the following formula:

$$\textbf{ERSAFHRS}_{qced} = \textbf{AFHOURS}_{qced} \,/ \sum_{tp} \textbf{HOURS}_{qse(tp)d}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
ERSAFHRS_{qced}	None	The ratio of Availability Factor Hours (AFHOURS_{qced}) to the total awarded hours in the ERS Standard Contract Term *s* for ERS Resource *e* per ERS service type *d*.

AFHOURS_{qced}	Hours	The total number of the ERS Resource's obligated hours in ERS Contract Period *c*, minus any hours during that time excluded for purposes of computing availability.
$\text{HOURS}_{qse(tp)d}$	Hours	The total number of awarded hours for ERS Resource *e* for ERS Time Period *tp* in the ERS Standard Contract Term *s*.
q	None	A QSE.
s	None	ERS Standard Contract Term.
c	None	ERS Contract Period.
e	None	Individual ERS Resource.
tp	None	ERS Time Period.
d	None	ERS service type (Weather-Sensitive ERS-10, Non-Weather-Sensitive ERS-10, Weather-Sensitive ERS-30, or Non-Weather-Sensitive ERS-30).

(d) An ERS Resource shall be deemed to have met its availability requirements for an ERS Contract Period if ERSAFHRS for the ERS Contract Period is less than 0.5 and if the ERS Resource achieves an ERSAFCOMB greater than or equal to the value calculated in the formula below:

$$\mathbf{3.8 * ERSAFHRS}_{qced} \mathbf{- 3.8 * (ERSAFHRS}_{qced}\mathbf{)}^2$$

(e) An ERS Resource that is deemed to have met its availability requirements under paragraph (d) above shall have its availability factor for that ERS Contract Period set to 1.0.

8.1.3.1.4 Event Performance Criteria for Emergency Response Service Resources

(1) No later than 45 days after the end of an ERS Standard Contract Term in which one or more ERS deployment events occurred, ERCOT shall provide each QSE representing ERS Resources with an event performance report containing the results of ERCOT's evaluation of the event(s). The report shall contain:

(a) For each event, the ERS event performance factor (ERSEPF) for each ERS Resource in the QSE's ERS portfolio, as described in this Section;

(b) For each event, the QSE's portfolio-level event performance factor, as described in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities;

(c) The QSE's portfolio-level event performance factor for the ERS Standard Contract Term, as described in Section 8.1.3.3.

(2) An ERS Resource's performance shall not be evaluated for an ERS deployment if one of the following is true:

(a) The Resource is in a ten-hour recovery period following a prior deployment at the beginning of the sustained response period of the deployment;

(b) The ERS Resource does not have an obligation for at least one full interval during the Sustained Response Period of that event;

(c) For Non-Weather-Sensitive ERS Resources, one or more sites of an ERS Resource were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline. QSEs must provide verification of such events from the TDSP or Meter Reading Entity (MRE); or

(d) For Weather-Sensitive ERS Resources, 10% or more sites of an ERS Load were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline.

(3) Otherwise, ERCOT shall evaluate an ERS Resource's performance during an ERS deployment based on the following criteria:

(a) Within the applicable ramp period, ERS Loads shall curtail Load and ERS Generators shall output energy and reach a level of energy injection to the ERCOT System in accordance with their ERS contractual obligations. The ramp period for ERS Resources in ERS-10 is ten minutes. The ramp period for ERS Resources in ERS-30 is 30 minutes.

(b) An ERS Load on a default baseline is expected to not increase its Load during the ramp period prior to an ERS test or deployment event. ERCOT will deem repeated occurrences of such Load increases to be a violation of the Protocols.

(c) ERCOT shall measure each ERS Resource's performance throughout the duration of an ERS deployment event by analyzing 15-minute interval meter data associated with the ERS Resource. ERCOT will compute an ERSEPF for each ERS Resource based upon this analysis.

(i) The ERSEPF is computed as the time-weighted arithmetic average of the EIPFs for the Sustained Response Period. An EIPF is computed for the ERS Resource for each of the 15-minute intervals in an ERS Sustained Response Period for which the ERS Resource has contracted capacity. If the last interval of the Sustained Response Period has an interval fraction (IntFrac) of less than one, the EIPF for that interval shall be excluded for the computation of ERSEPF. For an interval, EIPF_i is computed as follows:

$$\text{EIPF}_i = \text{Max}(\text{Min}(((\text{Base\_MWh}_i - \text{Actual\_MWh}_i) / (\text{IntFrac}_i * \text{OFFERMW})),1),0)$$

The above variables are defined as follows:

Variable	Unit	Description
IntFrac $_i$	None	Interval fraction for that ERS Resource for that interval.
Base_MWh $_i$	MWh	For an ERS Load on a default baseline, the aggregated sum of baseline MWh values estimated by ERCOT for all sites in the ERS Load for that interval. For an ERS Load assigned to the alternate baseline, the sum of the ERS Load's OFFERMW and maximum base Load for that interval. For a stand-alone ERS Generator or an ERS Generator co-located and jointly evaluated with an ERS Load, the net energy injected to the ERCOT System for that interval. For an ERS Generator co-located with, but evaluated separately from an ERS Load, the energy output of the ERS Generator.
Actual_MWh $_i$	MWh	For an ERS Load, the aggregated sum of the actual MWh values for all sites in the ERS Load for that interval. For an ERS Generator, the ERS Generator's declared injection capacity, expressed in units of MWh.
OFFERMW	MWh	The ERS Resource's contracted capacity for that interval expressed in units of MWh.
i	None	An interval.

and where IntFrac $_i$ corresponds to the fraction of time for that interval for which the Sustained Response Period is in effect and is computed as follows:

$$\text{IntFrac}_i = (\text{CEndT}_i - \text{CBegT}_i) / 15$$

The above variables are defined as follows:

Variable	Unit	Description
IntFrac $_i$	None	Interval fraction for that ERS Resource for that interval.
CBegT $_i$	Minutes	If the Sustained Response Period begins after the start of that interval, the time in minutes from the beginning of that interval to the beginning of the Sustained Response Period, otherwise it is zero.
CEndT $_i$	Minutes	If the Sustained Response Period ends during that interval, the time in minutes from the beginning of that interval to the end of the Sustained Response Period, otherwise it is 15.
i	None	An interval.

(ii) For an ERS Load assigned to an alternate baseline, if the IntFrac for the first interval of the Sustained Response Period is less than one, the EIPF for that interval shall be calculated as follows:

(A) If the actual Load of the full 15-minute interval is less than the maximum base Load, the EIPF for that interval shall be set to one.

(B) If the QSE submits interval data for the day of the event that is more granular than at the 15-minute interval level that shows the average Load for the ERS Resource was below its maximum base Load for the portion of the interval in the Sustained Response Period, the EIPF for that interval shall be set to one. This submitted data must be in a format acceptable to ERCOT and include, at a minimum, the actual Load and associated time stamps.

(C) If the QSE submits other documentary evidence that ERCOT determines, in its discretion, demonstrates the average Load for the ERS Resource was below its maximum base Load for the portion of the interval in the Sustained Response Period, the EIPF for that interval shall be set to one. The documentary evidence must be supported by a sworn affidavit.

(D) If none of the above applies, then ERCOT shall calculate EIPF using the formula in subsection (i) above with $Base\_MWh_i$ determined using one of the baselines described in the document titled “Demand Response Baseline Methodologies” on ERCOT.com.

(iii) In any ERS Standard Contract Term in which ERCOT has deployed ERS, the ERSEPF for an ERS Resource shall be the time-weighted average of the event performance factors for all events for which the ERS Resource was deployed.

(iv) Irrespective of its ERSEPF, an ERS Resource shall be deemed to have met its event performance requirements if it is an ERS Load determined by ERCOT to have met its Load reduction obligations in the ERS deployment event if measured on one of ERCOT’s established default baseline types other than the baseline type selected by the QSE, and ERCOT determines that the different baseline more accurately represents the ERS Load’s Demand response contribution.

(4) For an ERS deployment event, ERCOT shall calculate EIPFs and an ERSEPF for a Weather-Sensitive ERS Load, using actual 15-minute interval meter data, or, for Distributed Renewable Generation (DRG) that has been designated by the QSE to be evaluated by using its native load calculated 15-minute interval native load data, consistent with the provisions of paragraph (3)(c)(i) above. No other provisions in paragraph (3) above shall apply to Weather-Sensitive ERS Loads.

(5) Regardless of the number of enrolled sites in the Weather-Sensitive ERS Load at the time of an event or test, the contracted capacity value (OFFERMW) used will be the value submitted by the QSE in its offer.

8.1.3.2 Testing of Emergency Response Service Resources

(1) ERCOT may conduct an unannounced test of any ERS Resource at any time during an ERS Time Period in which the ERS Resource is contracted to provide ERS. Prior to the beginning of a Standard Contract Term, a QSE may request that one or more of its ERS Resources awarded in ERS-30 be tested as if subject to a ten-minute ramp during that ERS Standard Contract Term. The duration of a test will not count toward the ERS Resource's maximum cumulative deployment time for an ERS Contract Period.

(a) For Non-Weather-Sensitive ERS Resources, ERCOT shall determine a test performance factor for each test using the methodology defined in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources.

(i) The test performance factors for Non-Weather-Sensitive ERS Resources resulting from those tests will be used in Settlement for that and subsequent ERS Standard Contract Terms as specified in Section 8.1.3.3, Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities.

(ii) A test shall be deemed to be successful if the ERS Resource achieves both a test performance factor of 0.95 or greater and an EIPF for the full first interval of the test of 0.95 or greater.

(iii) An ERS Resource for which the most recent test with a ten-minute ramp was successful shall not be subject to a test for at least 330 days regardless of whether the ERS Resource is participating in ERS-10 or ERS-30.

(iv) An ERS Resource for which the most recent test with a 30-minute ramp was successful shall not be subject to a test for at least 330 days unless the ERS Resource participates in ERS-10 during that period.

(v) An ERS Resource participating in ERS-10 that meets its ERS-10 performance obligations for all ERS deployment events by achieving both an event performance factor of 0.95 or greater and an EIPF for the full first interval of 0.95 or greater during an ERS Standard Contract Term shall not be subject to a test for ERS-10 or ERS-30 for at least 330 calendar days following the date of the last deployment of ERS-10 during that ERS Standard Contract Term.

(vi) An ERS Resource participating in ERS-30 that meets its ERS-30 performance obligations for all ERS deployment events by achieving both an event performance factor of 0.95 or greater and an EIPF for the full first interval of 0.95 or greater during an ERS Standard Contract Term shall not be subject to a test for ERS-30 for at least 330 calendar days following the date of the last deployment of ERS-30 during that ERS Standard Contract Term.

(vii) Notwithstanding the foregoing:

(A) If the ERSAFCOMB for an ERS Resource for an ERS Standard Contract Term consisting of a single ERS Contract Period is less than 0.85, or the ERSAFCOMB for an ERS Resource for an ERS Contract Period with a duration that is less than an ERS Standard Contract Term is lower than the threshold specified in paragraph (4)(d) of Section 8.1.3.1.3.3, Contract Period Availability Calculations for Emergency Response Service Resources, ERCOT may re-test that ERS Resource without regard to the 330 day limit specified above.

(B) If an ERS Resource is contracted to provide services under a Must-Run Alternative (MRA) Agreement and has an ERS obligation during an overlapping ERS Standard Contract Term, ERCOT may conduct additional testing to verify the site's ability to provide both services on the same or consecutive days. Such testing may be conducted without regard to the 330 day limit specified above and without regard to any recovery periods allowed for either ERS or the MRA Agreement.

(C) If a single TDSP-metered Premise has more than one ERS site and those ERS sites participate in different ERS Resources, then all of those ERS Resources will be subject to testing if any one of the ERS Resources is subject to testing.

(b) Testing will be considered void and would require re-testing for any non-weather-sensitive Resources if one or more sites of an ERS Resource were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline. QSEs must provide verification of such events from the TDSP or MRE.

(c) For Weather-Sensitive ERS Resources, ERCOT shall conduct unannounced testing of each Weather-Sensitive ERS Load at least once but no more than twice per month of obligation during an ERS Standard Contract Term, unless testing has been superseded by deployment events as described in paragraph (vii) below.

(i) The tests will be conducted according to normal ERS testing procedures.

(ii) At the time of Dispatch during a test, ERCOT will not advise the QSE of the test duration, which may vary from one full 15-minute interval to 12 full 15-minute intervals.

(iii) ERCOT may conduct a test during any of a Weather-Sensitive ERS Load's obligated hours. However, tests will generally be targeted toward periods of peak weather conditions.

(iv) For a Weather-Sensitive ERS Load assigned to the control group baseline, for each test ERCOT will designate a single group which shall be removed from the test population that will serve as the control group.

(v) ERCOT shall calculate a test performance factor for each test of a Weather-Sensitive ERS Load using the event performance methodology described in Section 8.1.3.1.4.

(vi) The QSE is responsible for managing group assignments and for deploying only the sites dispatched by ERCOT during a test.

(vii) ERCOT may reduce the number of tests administered by the number of deployment events during the ERS Standard Contract Term.

(viii) The test performance factors for Weather-Sensitive ERS Resources shall always be set to one for use in Settlement for the ERS Standard Contract Term.

(ix) Testing will be considered void for any weather-sensitive Resources if 10% or more sites of a weather-sensitive Resource were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline. QSEs must provide verification of such events from the TDSP or MRE.

(2) ERCOT shall conduct an unannounced test of an ERS Resource that has been suspended from participation in ERS pursuant to Section 8.1.3.3. ERCOT will conduct such a test only after the QSE representing the ERS Resource has communicated to ERCOT a request for reinstatement of the suspended ERS Resource.

(3) An ERCOT unannounced test of an ERS Generator must demonstrate injection of energy to the ERCOT System. The use of Load banks is prohibited for ERCOT unannounced tests.

(4) If an ERS Generator is co-located with an ERS Load as specified in Section 8.1.3.1.2, Performance Evaluation for Emergency Response Service Generators, ERCOT shall test both such ERS Resources simultaneously and the following shall apply:

(a) Test performance of the ERS Load and the ERS Generator shall be evaluated jointly and attributed to both if the ERS Load is assigned to a default baseline or is assigned to the alternate baseline and the QSE elected for joint evaluation at the beginning of the ERS Standard Contract Term.

(b) Test performance of the ERS Load and the ERS Generator shall be evaluated separately if the ERS Load is assigned to the alternate baseline and the QSE elected for separate evaluation at the beginning of the ERS Standard Contract Term. If the separately evaluated ERS Load has no obligation greater than 100 kW in any ERS Time Period and does not meet the criteria for a successful test as defined in item (1)(a)(ii) above, the following shall apply:

(i) If the interval data measured by the metering on the output of the generator(s) meets the criteria for a successful test as defined in item (1)(a)(ii) above, for the combined obligation of the ERS Load and the ERS Generator, then both the ERS Load and the ERS Generator will be deemed to have performed successfully for that ERS test.

(ii) Otherwise, the ERS Load will be considered to have not performed successfully for that ERS test.

(5) In order to assist QSEs and ERS Resources in managing environmental compliance, ERCOT shall limit the cumulative duration of Sustained Response Periods of testing of an ERS Resource to a maximum of one hour per ERS Standard Contract Term unless otherwise required to conduct re-testing.

(6) Notwithstanding paragraph (5) above, Weather-Sensitive ERS Resources shall be subject to testing as described in paragraph (1)(c) above.

8.1.3.3 Payment Reductions and Suspension of Qualification of Emergency Response Service Resources and/or their Qualified Scheduling Entities

8.1.3.3.1 Suspension of Qualification of Non-Weather-Sensitive Emergency Response Service Resources and/or their Qualified Scheduling Entities

(1) If a QSE's portfolio-level availability factor and event performance factors as calculated in Section 8.1.3.3.3, Performance Criteria for Qualified Scheduling Entities Representing Non Weather-Sensitive Emergency Response Service Resources, both equal or exceed 0.95, the QSE will be deemed to have met its ERS performance requirements for the ERS Contract Period, and the QSE and its ERS Resources are not subject to suspension.

(2) If a QSE fails to meet its portfolio-level availability and/or event performance requirements as described in Section 8.1.3.3.3, ERCOT shall take the following actions:

(a) If a QSE failure is based only on event performance failure and ERS Resources that comprise 95% or more of the QSE's obligation for each of the events in the ERS Contract Term are deemed to have met their obligations, the QSE shall be deemed to have met its event performance requirements for the ERS Contract Term; otherwise

(b) ERCOT may suspend the QSE from participation in ERS, and the QSE may be subject to administrative penalties imposed by the PUCT. ERCOT may consider mitigating factors such as equipment failures and Force Majeure Events in determining whether to suspend the QSE.

(3) If a QSE's portfolio-level availability factor is less than 0.95 excluding the intervals for Resources that had one or more sites of an ERS Resource disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline, ERS Resources in that portfolio that were not disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline shall be subject to the following:

(a) If an ERS Resource in the QSE's portfolio achieves an availability factor of 0.85 or greater, the ERS Resource shall not be subject to a reduction of its availability factor;

(b) If an ERS Resource achieves an ERSAFCOMB less than 0.85 for an ERS Standard Contract Term consisting of a single ERS Contract Period, or achieves an ERSAFCOMB lower than the threshold specified in paragraph (4)(d) of Section 8.1.3.1.3.3, Contract Period Availability Calculations for Emergency Response Service Resources, for an ERS Contract Period with a duration that is less than an ERS Standard Contract Term, then the ERS Resource's availability factor shall be squared; and

(c) If the availability factor for one or more ERS Resources is squared pursuant to paragraph (b) above, ERCOT shall compute the QSE's final portfolio-level availability factor using that modified availability factor.

(4) ERCOT shall calculate a QSE's portfolio-level event performance factor and interval performance factor for the first full interval of that event. The portfolio for this purpose shall consist of ERS Resources that did not have any sites that were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline. If either the portfolio-level event performance factor or the interval performance factor for the first full interval of the Sustained Response Period is less than 0.95, ERCOT shall determine final event performance factors for ERS Resources in the portfolio as follows:

(a) If an ERS Load in the QSE's portfolio is not co-located with an ERS Generator or is evaluated separately, as specified in Section 8.1.3.1.2, Performance Evaluation for Emergency Response Service Generators, the final event performance factor for the ERS Load shall be determined as follows:

(i) If the ERS Load achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the

Sustained Response Period of 0.95 or greater, the final event performance factor shall be set equal to the original event performance factor.

(ii) If the ERS Load achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of 0.95 or greater, the baseline for that ERS Load shall be multiplied by a reduction factor that results in the final event performance factor being equal to the square of its original event performance factor.

(iii) If the ERS Load achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the baseline for that ERS Resource shall be multiplied by a reduction factor that results in the final event performance factor being equal to 0.75 times its original event performance factor.

(iv) If the ERS Load achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the baseline for that ERS Resource shall be multiplied by a reduction factor that results in the final event performance factor being equal to 0.75 times the square of its original event performance factor.

(b) If an ERS Generator in the QSE's portfolio, is not co-located with an ERS Load, the final event performance factor for the ERS Generator shall be determined as follows:

(i) If the ERS Generator achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the Sustained Response Period of 0.95 or greater, the final event performance factor shall be set equal to original event performance factor.

(ii) If the ERS Generator achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of 0.95 or greater, the net energy injected to the ERCOT System by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final event performance factor being equal to the square of its original event performance factor.

(iii) If the ERS Generator achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the net energy injected to the ERCOT System by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final event performance factor being equal to 0.75 times its original event performance factor.

(iv) If the ERS Generator achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the net energy injected to the ERCOT System by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final event performance factor being equal to 0.75 times the square of its original event performance factor.

(c) If an ERS Generator in the QSE's portfolio, is co-located with an ERS Load and is evaluated separately, as specified in Section 8.1.3.1.2, the final event performance factor for the ERS Generator shall be determined as follows:

(i) If the ERS Generator achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the Sustained Response Period of 0.95 or greater, the final event performance factor shall be set equal to original event performance factor.

(ii) If the ERS Generator achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of 0.95 or greater, the energy output by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final event performance factor being equal to the square of its original event performance factor.

(iii) If the ERS Generator achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the energy output by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final event performance factor being equal to 0.75 times its original event performance factor.

(iv) If the ERS Generator achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the energy output by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final event performance factor being equal to 0.75 times the square of its original event performance factor.

(d) If an ERS Load and an ERS Generator in a QSE's portfolio, are co-located and are evaluated jointly, as specified in Section 8.1.3.1.2, the final event performance factor shall be determined as follows:

(i) If the combined performance of the ERS Load and ERS Generator achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the Sustained Response

Period of 0.95 or greater, the final event performance factor for both ERS Resources shall be set equal to original event performance factor.

(ii) If the combined performance of the ERS Load and ERS Generator achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of 0.95 or greater, the net energy injected to the ERCOT System by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final combined event performance factor being equal to the square of its original combined event performance factor. If a reduction factor of zero results in the combined event performance factor being greater than the square of the original combined event performance factor, the net energy injected to the ERCOT System shall be set to zero for all intervals in the event and the baseline for the ERS Load shall be multiplied by a reduction factor that results in the final combined event performance factor being equal to the square of the original combined event performance factor.

(iii) If the combined performance of the ERS Load and ERS Generator achieves an event performance factor of 0.95 or greater and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the net energy injected to the ERCOT System by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final combined event performance factor being equal to 0.75 times its original event performance factor. If a reduction factor of zero results in the combined event performance factor being greater than 0.75 times its original event performance factor, the net energy injected to the ERCOT System shall be set to zero for all intervals in the event and the baseline for the ERS Load shall be multiplied by a reduction factor that results in the final combined event performance factor being equal to 0.75 times its original event performance factor.

(iv) If the combined performance of the ERS Load and ERS Generator achieves an event performance factor of less than 0.95 and an interval performance factor for the first full interval of the Sustained Response Period of less than 0.95, the net energy injected to the ERCOT System by the ERS Generator for each interval of the event shall be multiplied by a reduction factor that results in the final combined event performance factor being equal to 0.75 times the square of its original event performance factor. If a reduction factor of zero results in the combined event performance factor being greater than 0.75 times the square of its original event performance factor, the net energy injected to the ERCOT System shall be set to zero for all intervals in the event and the baseline for the ERS Load shall be multiplied by a reduction factor that results in the final combined event performance factor being equal to 0.75 times the square of its original event performance factor.

(e) If the final event performance factor for one or more ERS Resources in a QSE's portfolio is reduced pursuant to paragraphs (a) through (d) above, ERCOT shall re-compute the QSE's final portfolio-level event performance factor using each ERS Resource's final event performance factor.

(5) If an ERS Resource, in accordance with Section 8.1.3.2, Testing of Emergency Response Service Resources, has failed any two consecutive tests in an ERS Standard Contract Term, or has failed both the first test in an ERS Standard Contract Term and the most recent prior test occurring within 365 days of that first failed test, ERSTESTPF shall be set to the lower of 0.75 or the average of those two test performance factors and shall be used in calculating the payment to the QSE for the ERS Standard Contract Term during which the second failure occurred. Otherwise, ERSTESTPF shall be set to 1.0.

(6) Notwithstanding the provisions of paragraph (5) above, if an ERS Resource, in accordance with Section 8.1.3.2, has failed the most recent three consecutive tests within a 365 day period, then ERSTESTPF for the ERS Standard Contract Term in which the most recent failure has occurred, shall be determined as follows:

(a) If the average of ERSTESTPF for those three tests is equal to 0.90 or greater, ERSTESTPF shall be set to 0.5.

(b) If the average of ERSTESTPF for those three tests is less than 0.90, ERSTESTPF shall be set zero.

(c) If the ERS Resource has failed the most recent four consecutive tests within a 365 day period, then ERSTESTPF for the ERS Standard Contract Term in which the most recent failure has occurred, shall be set to zero.

(7) Notwithstanding the provisions of paragraphs (5) and (6) above, if an ERS Resource, in accordance with Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, successfully deploys in all ERS deployment events in which the ERS Resource has an obligation during that ERS Standard Contract Term, ERSTESTPF shall be set to 1.0 for that ERS Standard Contract Term.

(8) If a Governmental Authority issues a written determination that an ERS Resource is in violation of any environmental law that would preclude the ERS Resource's compliance with its ERS availability or deployment obligations, ERCOT shall treat the ERS Resource as having no availability for the remainder of the Standard Contract Term following the Governmental Authority's determination and shall treat the Resource as having an event performance factor of zero for any deployments in the remaining portion of the ERS Standard Contract Term. ERCOT shall also suspend the ERS Resource's participation in ERS until the ERS Resource's QSE certifies to ERCOT in writing that the violation has been remedied and that the ERS Resource may lawfully participate in ERS.

(9) If a QSE is suspended pursuant to paragraph (2) above, each of the QSE's ERS Resources whose availability or event performance factors was reduced in accordance with paragraphs (3) or (4) above also shall be suspended, and each of the sites in those

ERS Resources shall also be suspended. The duration of the suspension for such ERS Resources and sites shall be one ERS Standard Contract Term. ERCOT shall reject offers for ERS Resources that are suspended or that contain one or more suspended sites. Notwithstanding the foregoing, ERCOT may choose not to suspend an ERS Resource if it determines that the reduced availability or event performance factor was attributable to the fault of its QSE or to one or more mitigating factors, such as equipment failures and Force Majeure Events.

(10) The suspension of an ERS Resource or a QSE representing an ERS Resource shall begin on the day following the expiration of the current or most recent ERS obligation.

(11) ERCOT may reinstate an ERS Resource's eligibility to offer into ERS upon the ERS Resource's satisfactory completion of the reinstatement process, including a test conducted by ERCOT, as described in Section 8.1.3.2 and in the ERS technical requirements.

8.1.3.3.2 Payment Reduction and Suspension of Qualification of Weather-Sensitive Emergency Response Service Loads and/or their Qualified Scheduling Entities

(1) If the QSE portfolio-level event performance factor for the QSE's portfolio of Weather-Sensitive ERS Loads for the ERS Contract Period as calculated in Section 8.1.3.3.4, Performance Criteria for Qualified Scheduling Entities Representing Weather-Sensitive Emergency Response Service Loads, is greater than or equal to 0.90 or if 10% or more sites of an ERS Load were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline, ERCOT shall not impose a payment reduction for any of the those ERS Loads. Otherwise, ERCOT shall compute QSE portfolio-level Demand reduction values for each test and event throughout the ERS Contract Period as the greater of zero or the portfolio-level baseline estimate for each interval less the portfolio-level actual Load for that interval. The relationship of the Demand reduction values for each ERS Load to actual weather shall be modeled and used to derive a time-period specific Demand reduction value that would be realized under normalized peak weather conditions. If the normalized peak Demand reduction value for each ERS Time Period, summed across all ERS Loads in the portfolio is greater than or equal to 90% of the QSE's total offered MW capacity in that time period, ERCOT shall not impose a payment reduction for any of the ERS Loads in the portfolio.

(2) For an ERS deployment event for a Weather-Sensitive ERS Load with three or more full intervals in the Sustained Response Period, if the ERS Load's EIPF for the first full interval of the Sustained Response Period is less than 75% of the average EIPF for the remaining full intervals of the Sustained Response Period, the baseline used to evaluate the ERS Load shall be reduced to the level at which the ERSEPF for that event or test is equal to 0.75 times the ERSEPF determined by using the initial baseline.

(3) If the provisions of paragraph (1) above are not met, ERCOT shall reduce a QSE's payment for Weather-Sensitive ERS Load as follows:

(a) If the maximum number of sites in the ERS Load during the ERS Standard Contract Term is less than 80% of the number of sites projected by the QSE at the time of offer submission, as described in paragraph (15) of Section 3.14.3.1, Emergency Response Service Procurement, the baseline used to evaluate the Weather-Sensitive ERS Load shall be reduced to the level at which the ERSEPF is equal to the square of the ERSEPF determined by using the initial baseline.

(b) For all events occurring in an ERS Time Period, if, for that ERS Time Period the normalized peak Demand reduction value per site within the Weather-Sensitive ERS Load is less than 90% of the average Demand reduction value per site, based on the QSE's offer for that ERS Time Period, and the ERS Load's ERSEPF for an event in that ERS Time Period is less than 0.90, the baseline used to evaluate the ERS Load for that event shall be reduced to the level at which the ERS Load's ERSEPF is equal to the square of the ERSEPF determined by using the initial baseline.

(c) If either paragraph (3)(a) or (b) above require a payment reduction, but not both, and the normalized peak demand reduction for the resource is greater than or equal to 90% of the QSE's offered MW capacity, no payment reduction for the event shall be imposed.

(d) If the provisions of both paragraphs (3)(a) and (b) above require the ERSEPF to be squared, the baseline used to evaluate the ERS Load shall be reduced to the level at which the ERSEPF for the ERS Load is equal to the cube of the ERSEPF determined by using the initial baseline.

(e) If an ERS Load's obligation is exhausted during an ERS Contract Period, the provisions of paragraphs (3)(a), (b), and (c) above shall not apply.

(f) Baseline reductions required pursuant to paragraphs (3)(a), (b), and (c) above shall be applied to the initial baseline calculated by ERCOT. If a baseline reduction pursuant to paragraph (2) above also is required, that reduction shall be based on the adjusted baseline after applying the reductions provided for in paragraphs (3)(a), (b), and (c) above.

(g) If the final event performance factor for one or more ERS Loads in a QSE's portfolio of Weather-Sensitive ERS Loads is reduced pursuant to paragraphs (2) or (3)(a), (b), or (d) above, ERCOT shall re-compute the QSE's final portfolio-level event performance factor using each ERS Load's adjusted baselines.

8.1.3.3.3 Performance Criteria for Qualified Scheduling Entities Representing Non-Weather-Sensitive Emergency Response Service Resources

(1) A QSE's ERS performance will be evaluated based on its portfolio's performance for each of the four ERS service types during ERS deployment events and on the overall availability of its portfolio in an ERS Standard Contract Term, as follows:

(a) Availability:

- (i) ERCOT shall calculate a portfolio-level availability factor for each QSE's ERS portfolio for each ERS service type for each ERS Time Period in an ERS Contract Period using the methodologies defined in Section 8.1.3.1.3, Availability Criteria for Emergency Response Service Resources, except that the availability factor for each ERS Time Period will be allowed to exceed 1.0. ERCOT shall then calculate a single time- and capacity-weighted availability factor for the QSE portfolio for each ERS service type for the ERS Contract Period using the methodologies defined in Section 8.1.3.1.3.

- (ii) ERCOT shall then calculate a single time and capacity-weighted availability factor for the QSE portfolio for the ERS Standard Contract Term and the ERS service type, which will be capped at 1.0.

  - (A) For an ERS Standard Contract Term with a single ERS Contract Period, the QSE portfolio-level availability factor for each ERS service type for the ERS Standard Contract Term shall be the portfolio-level availability factor for each ERS service type for the ERS Contract Period.

  - (B) For an ERS Standard Contract Term with multiple ERS Contract Periods, ERCOT shall compute a QSE portfolio-level availability factor for each ERS service type for the ERS Standard Contract Term by averaging the QSE's availability factors across ERS Contract Periods and ERS Time Periods for each ERS service type, weighted according to time and capacity obligations.

- (iii) The QSE's portfolio-level availability factor for each ERS service type for the ERS Standard Contract Term will determine both the availability component of the ERS payment to the QSE and whether the QSE has met its ERS availability requirements. If the QSE's portfolio-level availability factor for each ERS service type for the ERS Standard Contract Term equals or exceeds 0.95, the QSE shall be deemed to have met its availability requirements for the ERS Standard Contract Term; otherwise, the QSE shall be deemed to have failed to meet this requirement. If the QSE's portfolio-level availability factor for either ERS service type for the ERS Standard Contract Term is less than 1.0, the QSE's ERS capacity payment shall be reduced according to the formulas in Section 6.6.11.1, Emergency Response Service Capacity Payments.

(b) Event Performance:

- (i) QSEs representing ERS Resources must meet performance standards specified in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, as applied on a portfolio-level basis.

ERCOT shall determine a QSE's portfolio-level event performance for each ERS service type by calculating a QSE portfolio-level event performance factor for each ERS deployment event. For purposes of evaluating ERS Loads, ERCOT shall establish a baseline representing the portfolio's estimated Load, or, for DRG that has been designated by the QSE to be evaluated by using its native load, calculated 15-minute interval native load data in the absence of the ERS deployment event. For purposes of evaluating ERS Generators, ERCOT shall compute portfolio-level injection of energy to the ERCOT System. Using this data, ERCOT shall calculate a QSE portfolio-level event performance factor for each ERS deployment event for each ERS service type based on the weighted average of the event interval performance factors, weighted by the total obligation and IntFrac.

(ii) ERCOT shall then calculate an ERSEPF_{qrd} for the ERS Standard Contract Term, which will be capped at 1.0. For an ERS Standard Contract Term with no ERS deployment events, the ERSEPF_{qrd} for the ERS Standard Contract Term shall be set to 1.0.

(A) For an ERS Standard Contract Term with a single ERS deployment event, the ERSEPF_{qrd} for the ERS Standard Contract Term shall be the QSE portfolio-level event performance factor for the event.

(B) For an ERS Standard Contract Term with multiple ERS deployment events, ERCOT shall compute the ERSEPF_{qrd} for the ERS Standard Contract Term by averaging the QSE portfolio-level interval performance factors for all of the deployment events for each ERS service type, weighted by the total obligation and IntFrac.

(iii) The ERSEPF_{qrd} for an ERS Standard Contract Term will determine both the event performance component of the ERS payment to the QSE and whether the QSE has met its ERS event performance requirements for that ERS service type. If an ERSEPF_{qrd} for an ERS Standard Contract Term is greater than or equal to 0.95, the QSE will be deemed to have met its event performance requirements for the ERS Standard Contract Term for that ERS service type; otherwise, the QSE shall be deemed to have failed to meet this requirement. If a QSE's ERSEPF_{qrd} is less than 1.0 for the Standard Contract Term, the QSE's ERS capacity payment shall be reduced according to the formulas in Section 6.6.11.1. For purposes of calculating an ERSEPF_{qrd}, any ERS Resource that was not subject to Dispatch during the event shall be treated as having met its obligation.

(iv) ERCOT will not include any Resources in the calculation of the ERSEPF_{qrd} if one or more sites of an ERS Resource were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline. QSEs must provide verification of such events from the TDSP or MRE.

(c) Ten-minute Deployment: Within ten minutes of ERCOT's issuance of a VDI to deploy ERS-10, a QSE shall ensure that each ERS Resource participating in ERS-10 in its portfolio deploys in accordance with its obligations. For each ERS-10 deployment event, ERCOT shall assess each QSE's compliance with this requirement by calculating a capacity-weighted QSE portfolio-level interval performance factor for the first full interval of the Sustained Response Period, using the methodologies defined in Section 8.1.3.1.4.

(d) Thirty-minute Deployment: Within 30 minutes of ERCOT's issuance of a VDI to deploy ERS-30, a QSE shall ensure that each ERS Resource participating in its portfolio deploys in accordance with its obligations. For each ERS-30 deployment event, ERCOT shall assess each QSE's compliance with this requirement by calculating a capacity-weighted QSE portfolio-level interval performance factor for the first full interval of the Sustained Response Period, using the methodologies defined in Section 8.1.3.1.4.

The above variables are defined as follows:

Variable	Unit	Description
ERSEPF_{qrd}	None	*ERS Event Performance Factor per QSE per ERS Standard Contract Term per ERS Service Type*—Event performance factor for QSE *q* in ERS Standard Contract Term *r* and ERS service type *d* as calculated pursuant to Section 8.1.3.3.1.
q	None	A QSE.
r	None	ERS Standard Contract Term.
d	None	ERS service type (Non-Weather-Sensitive ERS-10 or Non-Weather-Sensitive ERS-30).

(2) Failure by a QSE portfolio to meet its ERS event performance or availability requirements shall not be cause for revocation of the QSE's Ancillary Services qualification.

8.1.3.3.4 Performance Criteria for Qualified Scheduling Entities Representing Weather-Sensitive Emergency Response Service Loads

(1) A QSE's ERS performance will be evaluated based on the performance of its portfolio of Weather-Sensitive ERS Loads during ERS deployment events in an ERS Standard Contract Term as follows:

(a) ERCOT shall compute the following quantities at the QSE portfolio level for each interval of a deployment: MW obligation, baseline estimate and actual Demand as the sum of the respective quantities across the ERS Loads, or, for DRG that has been designated by the QSE to be evaluated by using its native load, calculated 15-minute interval native load data in the portfolio with obligations for that interval. In addition, ERCOT shall compute the QSE's portfolio-level prorated total obligations as the weighted sum of the obligations of the deployed ERS Loads weighted by the ratio the number of sites participating in the ERS Load during the event to the maximum number of sites projected by the QSE at the time of offer submission and the prorated interval fraction value (IntFrac) for each interval of a deployment as the average respectively of the interval fractions for each of the ERS Loads within its portfolio weighted by the ERS Load's obligation for that interval multiplied by the ratio of the number of sites participating in the ERS Load during the event to the maximum number of sites projected by the QSE at the time of offer submission.

(b) ERCOT shall compute the QSE's portfolio-level event interval performance factor for each interval of a deployment as specified in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, using the values computed in paragraph (a) above.

(c) ERCOT shall compute the QSE's portfolio-level Weather-Sensitive ERS Load event performance factor (ERSEPF) for each test and event as the weighted average of the event interval performance factors calculated in paragraph (b) above, weighted by the prorated obligation and interval fractions (IntFrac) computed in paragraph (a) above.

(d) ERCOT shall compute the QSE's portfolio-level Weather-Sensitive ERS Load event performance factor for the ERS Contract Period as the average of the event interval performance factors for all tests and events during the ERS Contract Period calculated in paragraph (b) above weighted by the prorated obligation and interval fractions computed in paragraph (a) above.

(e) ERCOT will not include any Weather-Sensitive ERS Loads in the calculation of the ERSEPF if 10% or more sites of an ERS Load were disabled or unverifiable due to events on the TDSP side of the meter affecting the supply, delivery or measurement of electricity either during the event or prior that impacts the creation of a credible baseline. QSEs must provide verification of such events from the TDSP or MRE.

8.1.3.4 ERCOT Data Collection for Emergency Response Service

(1) ERCOT will collect all data necessary to analyze offers, Self-Provision offers, and all availability and performance obligations of ERS Resources and their QSEs under the Protocols. QSEs and ERS Resources they represent are required to provide any data to ERCOT that ERCOT may require, as specified by ERCOT.

8.2 ERCOT Performance Monitoring

(1) ERCOT shall continually assess its operations performance for the following activities:

(a) Coordinating the wholesale electric market transactions;

(b) System-wide transmission planning; and

(c) Network reliability.

(2) The Technical Advisory Committee (TAC), or a subcommittee designated by TAC, shall review ERCOT's performance in controlling the ERCOT Control Area according to requirements and criteria set out in the TAC- and ERCOT Board-approved monitoring program. Assessments and reports include the following ERCOT activities:

(a) Transmission control:

(i) Transmission system availability statistics;

(ii) Outage scheduling statistics for Transmission Facilities Outages (maintenance planning, construction coordination, etc.); and

(iii) Metrics describing performance of the State Estimator;

(b) Resource control:

(i) Outage scheduling statistics for Resource facilities Outages (maintenance planning, construction coordination, etc.);

(ii) Resource control metrics as defined in the Operating Guides;

(iii) Metrics describing Reliability Unit Commitment (RUC) commitments and deployments;

(iv) Metrics describing conflicting instructions to Generation Resources from interval to interval;

(v) Metrics describing the overall Resource response to frequency deviations in the ERCOT Region; and

(vi) Voltage and reactive control performance;

(c) Settlement stability:

(i) Track number of price changes that occur after a Settlement Statement has posted for an Operating Day;

(ii) Track number and types of disputes submitted to ERCOT and their disposition;

(iii) Report on compliance with timeliness of response to disputes;

(iv) Number of resettlements required due to non-price errors pursuant to paragraphs (2) and (4) of Section 9.2.5, DAM Resettlement Statement, and paragraph (2) of Section 9.5.6, RTM Resettlement Statement;

(v) Other Settlement metrics; and

(vi) Availability of Electric Service Identifier (ESI ID) consumption data in conformance with Settlement timeline;

(d) Performance in implementing network model updates;

(e) Network Operations Model validation, by comparison to other appropriate models or other methods;

(f) System and Organization Control (SOC) audit results regarding ERCOT's market Settlements operations;

(g) Net Allocation to Load:

(i) ERCOT shall calculate and report on a quarterly basis all charges allocated to Load for all Qualified Scheduling Entities (QSEs) for each month for the most recent thirteen months expressed in total dollars. ERCOT will sum all charges allocated to Load for all QSEs, and divide that total by the total Real-Time Adjusted Metered Load (AML), showing results in dollars per MWh.

(ii) The Load-Allocated CRR Monthly Revenue Zonal Amount (LACMRZAMT), as calculated in paragraph (5) of Section 7.5.7, Method for Distributing CRR Auction Revenues, will be summed by Congestion Management Zone (CMZ) for each month for the most recent 13 months, and divided by the sum of the Real-Time AML by CMZ for each month, showing results in dollars per MWh per CMZ.

(iii) ERCOT will calculate the total dollars per MWh by CMZ by summing all charges allocated to Load for all QSEs, excluding LACMRZAMT, and dividing that total by the Real-Time AML; this rate will then be added to item (ii) above to calculate the total dollars per MWh by CMZ.

8.3 TSP Performance Monitoring and Compliance

(1) ERCOT shall develop a Technical Advisory Committee (TAC)- and ERCOT Board-approved Transmission Service Provider (TSP) monitoring program to be included in the Operating Guides for TSPs, which shall include the following:

(a) Real-Time data:

(i) Telemetry performance; and

(b) Compliance with model update requirements, including provision of network data in Common Informational Model (CIM) compatible format and consistency with the Transmission Element naming convention developed in accordance under Section 3, Management Activities for the ERCOT System.

[NPRR857: Replace Section 8.3 above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

8.3 TSP and DCTO Performance Monitoring and Compliance

(1) ERCOT shall develop a Technical Advisory Committee (TAC)- and ERCOT Board-approved Transmission Service Provider (TSP) and Direct Current Tie Operator (DCTO) monitoring program to be included in the Operating Guides for TSPs and DCTOs, which shall include the following:

(a) Real-Time data:

(i) Telemetry performance; and

(b) Compliance with model update requirements, including provision of network data in Common Informational Model (CIM) compatible format and consistency with the Transmission Element naming convention developed in accordance under Section 3, Management Activities for the ERCOT System.

8.4 ERCOT Response to Market Non-Performance

(1) ERCOT may require a Market Participant to develop and implement a corrective action plan to address its failure to meet performance criteria in this Section. The Market Participant must deliver a copy of this plan to ERCOT and must report to ERCOT periodically on the status of the implementation of the corrective action plan.

(2) ERCOT may revoke any or all Ancillary Service qualifications of any Generation Resource or Load Resource for continued material non-performance in providing Ancillary Service capacity or energy.

(3) ERCOT may suspend any Emergency Response Service (ERS) Resource for continued material non-performance in providing ERS.

8.5 Primary Frequency Response Requirements and Monitoring

8.5.1 Generation Resource and QSE Participation

[NPRR989: Replace Section 8.5.1 above with the following upon system implementation:]

8.5.1 Generation Resource, Energy Storage Resource, and QSE Participation

8.5.1.1 Governor in Service

(1) At all times a Generation Resource, Energy Storage Resource (ESR), Settlement Only Transmission Generator (SOTG), or Settlement Only Transmission Self-Generator (SOTSG) is On-Line, its Governor must remain in service and be allowed to respond to all changes in system frequency except during startup, shutdown, or testing. A Resource Entity may not reduce Primary Frequency Response on an individual Generation Resource, ESR, or Settlement Only Generator (SOG) even during abnormal conditions without ERCOT's consent (conveyed by way of the Resource Entity's Qualified Scheduling Entity (QSE)) unless equipment damage is imminent. All Generation Resources, ESRs, SOTGs, and SOTSGs that have capacity available to either increase output or decrease output in Real-Time must provide Primary Frequency Response, which may make use of that available capacity. Only Generation Resources or ESRs providing Regulation Up (Reg-Up), Regulation Down (Reg-Down), Responsive Reserve (RRS), or Non-Spinning Reserve (Non-Spin) from On-Line Resources, as specified in Section 8.1.1, QSE Ancillary Service Performance Standards, shall be required to reserve capacity that may also be used to provide Primary Frequency Response.

[NPRR863 and NPRR995: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) At all times a Generation Resource, Energy Storage Resource (ESR), Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) is On-Line, its Governor must remain in service and be allowed to respond to all changes in system frequency except during startup, shutdown, or testing. A Resource Entity may not reduce Primary Frequency Response on an individual Generation Resource, ESR, Settlement Only Generator (SOG), or SOTESS even during abnormal conditions without ERCOT's consent (conveyed by way of the Resource Entity's Qualified Scheduling Entity (QSE)) unless equipment damage is imminent. All Generation Resources, ESRs, SOTGs, SOTSGs, and SOTESSs that have capacity available to either increase output or decrease output in Real-Time must provide Primary Frequency Response, which may make use of that available capacity. Only Generation Resources or ESRs providing Responsive Reserve (RRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), ERCOT Contingency Reserve Service (ECRS), or Non-Spinning Reserve (Non-Spin) from On-Line Resources, as specified in Section

8.1.1, QSE Ancillary Service Performance Standards, shall be required to reserve capacity that may also be used to provide Primary Frequency Response.

[NPRR863, NPRR989, NPRR995, and NPRR1011: Insert applicable portions of paragraph (2) below upon system implementation for NPRR863, NPRR989, and NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

(2) Generation Resources and ESRs that do not have an RRS or Regulation Service Ancillary Service award shall set their Governor Dead-Band no greater than ±0.036 Hz from nominal frequency of 60 Hz. A Generation Resource or ESR that widens its Governor Dead-Band greater than what is prescribed in Nodal Operating Guide Section 2.2.7, Turbine Speed Governors, must update its Resource Registration data with the new dead-band value.

[NPRR995: Insert paragraph (3) below upon system implementation:]

(3) SOTGs, SOTSGs, and SOTESSs shall set their Governor Dead-Band no greater than ±0.036 Hz from nominal frequency of 60 Hz.

8.5.1.2 Reporting

(1) Each Resource Entity shall conduct applicable Governor tests on each of its Generation Resources and ESRs as specified in the Operating Guides. The Resource Entity shall provide test results and other relevant information to ERCOT. ERCOT shall make these results available to the Transmission Service Providers (TSPs).

(2) Generation Resource and ESR Governor modeling information required in the ERCOT planning criteria must be determined from actual Generation Resource or ESR testing described in the Operating Guides. Within 30 days of ERCOT’s request, the results of the latest test performed must be supplied to ERCOT and the connected TSP.

(3) Each QSE shall inform ERCOT as soon as practical when notified by its On-Line Generation Resource, ESR, SOTG, or SOTSG of the Governor being out-of-service. The QSE shall supply related logs to ERCOT upon request.

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

(3) Each QSE shall inform ERCOT as soon as practical when notified by its On-Line Generation Resource, ESR, SOTG, SOTSG, or SOTESS of the Governor being out-of-service. The QSE shall supply related logs to ERCOT upon request.

(4) If a Generation Resource or ESR trips Off-Line during a disturbance, as defined by the North American Electric Reliability Corporation (NERC), while providing Primary Frequency Response, the QSE shall report the cause of the failure to ERCOT as soon as the cause has been identified.

8.5.1.3 Wind-powered Generation Resource (WGR) Primary Frequency Response

(1) Wind-powered Generation Resources (WGRs) with Standard Generation Interconnection Agreements (SGIAs) signed after January 1, 2010 shall provide Primary Frequency Response to frequency deviations from 60 Hz. The WGR automatic control system design shall have an adjustable dead band that can be set as specified in the Operating Guides. The Primary Frequency Response shall be specified in the Operating Guides. For WGRs with SGIAs executed on or prior to January 1, 2010, those not already equipped with Primary Frequency Response shall by December 1, 2011 acquire that capability. Those WGRs that cannot technically be retrofitted with Primary Frequency Response capability shall submit an attestation to ERCOT by June 1, 2010 explaining the technical infeasibility. At ERCOT's sole discretion, those WGRs for which Primary Frequency Response is technically infeasible may be granted a permanent exemption from the requirement. ERCOT shall make a determination within 180 days of receipt of the attestation. If ERCOT does not grant an exemption, the WGR shall acquire the capability to provide Primary Frequency Response within 24 months of being notified of that determination. If ERCOT grants the exemption, then ERCOT may require the WGR to install alternate measures, such as over-frequency relays, that are technically feasible and would approximate Primary Frequency Response to events above 60.1 Hz.

8.5.2 Primary Frequency Response Measurements

(1) ERCOT, with the assistance of the appropriate Technical Advisory Committee (TAC) subcommittee, shall analyze the performance of Generation Resources, ESRs, SOTGs, SOTSGs, Resources capable of Fast Frequency Response (FFR), and Controllable Load Resources for all Frequency Measurable Events (FMEs) in accordance with the Operating Guides. In support of this analysis, ERCOT shall post the following:

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

(1) ERCOT, with the assistance of the appropriate Technical Advisory Committee (TAC) subcommittee, shall analyze the performance of Generation Resources, ESRs, SOTGs, SOTSGs, SOTESSs, Resources capable of Fast Frequency Response (FFR), and Controllable Load Resources for all Frequency Measurable Events (FMEs) in accordance with the Operating Guides. In support of this analysis, ERCOT shall post the following:

(a) ERCOT shall post on the ERCOT website the occurrence of an FME within 14 calendar days of occurrence.

(b) ERCOT shall post on the Market Information System (MIS) Certified Area for Performance, Disturbance, Compliance Working Group (PDCWG) analysis, the Primary Frequency Response Unit Performance for each Generation Resource, ESR, SOTG, SOTSG, and Controllable Load Resource that is measured in the FME.

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

(b) ERCOT shall post on the MIS Certified Area for Performance, Disturbance, Compliance Working Group (PDCWG) analysis, the Primary Frequency Response Unit Performance for each Generation Resource, ESR, SOTG, SOTSG, SOTESS, and Controllable Load Resource that is measured in the FME.

(c) ERCOT shall post on the ERCOT website a monthly report that displays the frequency response of the ERCOT System for a rolling average of the last six FMEs.

(d) ERCOT shall post on the ERCOT website an annual report that displays the minimum frequency response computation methodology of the ERCOT System.

(e) ERCOT shall post on the MIS Certified Area the Primary Frequency Response 12-month rolling average for each Generation Resource, ESR, SOTG, SOTSG, Resource capable of FFR, and Controllable Load Resource.

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

(e) ERCOT shall post on the MIS Certified Area the Primary Frequency Response 12-month rolling average for each Generation Resource, ESR, SOTG, SOTSG, SOTESS, Resource capable of FFR, and Controllable Load Resource.

8.5.2.1 ERCOT Required Primary Frequency Response

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

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

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

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

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

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

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

8.5.2.2 ERCOT Data Collection

(1) ERCOT shall collect all data necessary to analyze each FME.

ERCOT Nodal Protocols

Section 9: Settlement and Billing

November 15, 2022

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9 SETTLEMENT AND BILLING

9.1 General

9.1.1 Settlement and Billing Process Overview

(1) Settlement is the process used to resolve financial obligations between a Market Participant and ERCOT, including administrative and miscellaneous charges. Settlement also provides Transmission Billing Determinants to Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs). The Settlement and billing timeline and process for the Day-Ahead Market (DAM) is separate from the Settlement and billing timeline and process for the Day-Ahead Reliability Unit Commitment (DRUC) process, the Adjustment Period, and Real-Time operations (after this referred to together in this Section as the Real-Time Market (RTM)).

9.1.2 Settlement Calendar

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(o) Each Securitization Uplift Charge Initial Invoice will be issued under Section 27.4.1, Securitization Uplift Charge Initial Invoices;

(p) Payments for Securitization Uplift Charge Initial Invoices are due under Section 27.4.3, Payment Process for Securitization Uplift Charge Initial Invoices;

(q) Each Securitization Uplift Charge Reallocation Invoice will be issued under Section 27.4.2, Securitization Uplift Charge Reallocation Invoices;

(r) Payments for Securitization Uplift Charge Reallocation Invoices are due under Section 27.4.5, Payment Process for Securitization Uplift Charge Reallocation Invoices; and

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

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

9.1.3 Settlement Statement and Invoice Access

(1) A Statement or Invoice Recipient may access its Settlement Statements or Invoices electronically, using either of the following methods:

(a) Secured entry on the Market Information System (MIS) Certified Area;

(b) eXtensible Markup Language (XML) access to the MIS Certified Area.

9.1.4 Settlement Statement and Invoice Timing

(1) Unless expressly stated otherwise, the publication of each Settlement Statement and Invoice can occur as late as 2400 on its scheduled publication date.

9.1.5 Settlement Payment Convention

(1) A Settlement Statement or Invoice containing a negative amount represents a payment due by ERCOT to the Market Participant that received the Statement or Invoice. A Settlement Statement or Invoice containing a positive amount represents a payment due to ERCOT by the Market Participant that received the Statement or Invoice.

9.2 Settlement Statements for the Day-Ahead Market

9.2.1 Settlement Statement Process for the DAM

(1) ERCOT shall produce daily Settlement Statements for the Day-Ahead Market (DAM), as defined in Section 9.2.2, Settlement Statements for the DAM, that show a breakdown of Charge Types incurred in the DAM, including any administrative and miscellaneous charges applicable to the DAM. "Charge Types" are the various categories of specific charges referenced in Section 9.15.1, Charge Type Matrix.

9.2.2 Settlement Statements for the DAM

(1) ERCOT shall make each Settlement Statement for a DAM available on the date specified on the Settlement Calendar for that DAM by posting it on the Market Information System (MIS) Certified Area for the applicable Market Participant to which the Settlement Statement is addressed (Statement Recipient).

(2) A Settlement Statement for the DAM can be:

(a) A "DAM Statement," which is the Settlement Statement issued for a particular DAM;

(b) A "DAM Resettlement Statement," which corrects a DAM Statement.

(3) The Statement Recipient is responsible for accessing the statement from the MIS Certified Area.

(4) ERCOT shall create a DAM Statement for each DAM.

(5) ERCOT may create a DAM Resettlement Statement for the DAM, depending on the criteria set forth in Section 9.2.5, DAM Resettlement Statement.

(6) Each Settlement Statement for the DAM must denote:

(a) The applicable Operating Day;

(b) The Statement Recipient's name;

(c) The ERCOT identifier (settlement identification number issued by ERCOT);

(d) Status of the statement (DAM Statement or DAM Resettlement Statement);

(e) Statement version number;

(f) Unique statement identification code; and

(g) Charge Types settled.

(7) Settlement Statements for the DAM must break fees down by Charge Types into the appropriate one-hour Settlement Interval for that type.

(8) The Settlement Statement for the DAM must have a summary page of the corresponding detailed documentation.

9.2.3 DAM Settlement Charge Types

(1) ERCOT shall provide, on each Settlement Statement, the dollar amount for each DAM Settlement charge and payment. The DAM settlement "Charge Types" are:

(a) Section 4.6.2.1, Day-Ahead Energy Payment;

(b) Section 4.6.2.2, Day-Ahead Energy Charge;

(c) Section 4.6.2.3.1, Day-Ahead Make-Whole Payment;

(d) Section 4.6.2.3.2, Day-Ahead Make-Whole Charge;

(e) Section 4.6.3, Settlement for PTP Obligations Bought in DAM;

(f) Section 4.6.4.1.1, Regulation Up Service Payment;

(g) Section 4.6.4.1.2, Regulation Down Service Payment;

(h) Section 4.6.4.1.3, Responsive Reserve Payment;

(i) Section 4.6.4.1.4, Non-Spinning Reserve Service Payment;

[NPRR863: Insert item (j) below upon system implementation and renumber accordingly:]

(j) Section 4.6.4.1.5, ERCOT Contingency Reserve Service Payment;

(j) Section 4.6.4.2.1, Regulation Up Service Charge;

(k) Section 4.6.4.2.2, Regulation Down Service Charge;

(l) Section 4.6.4.2.3, Responsive Reserve Charge;

(m) Section 4.6.4.2.4, Non-Spinning Reserve Service Charge;

[NPRR863: Insert item (o) below upon system implementation and renumber accordingly:]

(o) Section 4.6.4.2.5, ERCOT Contingency Reserve Service Charge;

(n) Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM;

(o) Section 7.9.1.2, Payments for PTP Options Settled in DAM;

(p) Section 7.9.1.4, Payments for FGRs Settled in DAM;

(q) Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM;

(r) Section 7.9.1.6, Payments for PTP Options with Refund Settled in DAM; and

(s) Paragraph (2) of Section 7.9.3.3, Shortfall Charges to CRR Owners.

9.2.4 DAM Statement

(1) ERCOT shall produce a DAM Statement for each Statement Recipient for the given DAM on the second Business Day after the Operating Day.

9.2.5 DAM Resettlement Statement

(1) ERCOT shall issue DAM Resettlement Statements for a given Operating Day if the ERCOT Board finds that the DAM Locational Marginal Prices (LMPs), Market Clearing Prices for Capacity (MCPCs), or Settlement Point Prices are significantly affected by a software or other error under Section 4.5.3, Communicating DAM Results. ERCOT shall

also produce DAM Resettlement Statements required by resolution of Settlement and billing disputes. In addition, the ERCOT Board may, in its discretion, direct ERCOT to run a resettlement of any Operating Day, at any time, to address unusual circumstances.

(2) ERCOT shall issue a DAM Resettlement Statement for a given Operating Day due to errors other than errors in prices when:

(a) The total of all errors other than price errors results in an absolute value impact greater than 2% of the total DAM Statement amount for any single Statement Recipient for the Operating Day; and

(b) The impact to the Statement Recipient is greater than $200.00.

(3) ERCOT shall issue a DAM Resettlement Statement for an Operating Day if an error in the DAM Settlement, which does not otherwise meet the Protocol requirements for resettlement as specified in paragraphs (1) and (2) above, will prevent ERCOT from achieving revenue neutrality.

(4) No later than 150 days after each affected Operating Day, ERCOT shall resettle Operating Days with errors, other than errors in prices, with cumulative impacts that do not meet the threshold described in paragraph (2) above if the cumulative effect of errors to a single Statement Recipient in the 150 day window results in an absolute value impact greater than 1% of the total DAM Statement amounts for any Statement Recipient for the affected Operating Days, if this impact to the Statement Recipient is greater than $5,000.00.

(5) A DAM Resettlement Statement must reflect differences to financial records generated on the previous Settlement Statement for the given DAM.

9.2.6 Notice of Resettlement for the DAM

(1) While maintaining confidentiality of all Market Participants, ERCOT shall send a Market Notice in conjunction with the resettlement, indicating the resettlement of the DAM for a specific Operating Day and the date of issuance of the Resettlement Statements for the DAM. ERCOT shall include the following information in the notice of resettlement:

(a) Detailed description of reason(s) for resettlement;

(b) For the applicable Operating Day;

(c) Affected Charge Types; and

(d) Total resettled amount, by Charge Type.

9.2.7 Confirmation of Statement for the DAM

(1) It is the responsibility of each Statement Recipient to notify ERCOT if a Settlement

Statement for the DAM is not available on the MIS Certified Area on the date specified for posting of that Settlement Statement in the Settlement Calendar. Each Settlement Statement for the DAM is deemed to have been available on the posting date specified on the Settlement Calendar, unless ERCOT is notified to the contrary. If ERCOT receives notice that a Settlement Statement is not available, ERCOT shall make reasonable attempts to provide the Settlement Statement to the Statement Recipient, and ERCOT shall modify the Settlement and billing timeline accordingly for that Settlement Statement.

9.2.8 Validation of the Settlement Statement for the DAM

(1) The Statement Recipient is deemed to have validated each Settlement Statement for the DAM unless it has raised a Settlement and billing dispute under Section 9.14, Settlement and Billing Dispute Process.

9.2.9 Suspension of Issuing Settlement Statements for the DAM

(1) The ERCOT Board may direct ERCOT to suspend the issuance of any Settlement Statement for the DAM to address unusual circumstances. Any proposal to suspend settlements must be presented to the Technical Advisory Committee (TAC) for review and comment, in a reasonable manner under the circumstances, prior to such suspension.

9.3 *[RESERVED]*

9.4 *[RESERVED]*

9.5 Settlement Statements for Real-Time Market

9.5.1 Settlement Statement Process for the Real-Time Market

(1) ERCOT shall produce daily Settlement Statements for the Real-Time Market (RTM), as defined in Section 9.5.2, Settlement Statements for the RTM, that show a breakdown of Charge Types incurred in the RTM, including any administrative and miscellaneous charges applicable to the RTM.

9.5.2 Settlement Statements for the RTM

(1) ERCOT shall make each Settlement Statement for the RTM for an Operating Day available on the date specified on the Settlement Calendar for that Operating Day by posting it to the Market Information System (MIS) Certified Area for the applicable Statement Recipient.

(2) A Settlement Statement for the RTM can be:

- (a) An "RTM Initial Statement," which is the first iteration of a Settlement Statement issued for a particular Operating Day;
- (b) An "RTM Final Statement," which is the statement issued at the end of the 55th day following the Operating Day;
- (c) An "RTM Resettlement Statement," which is the statement using corrected Settlement data due to resolution of disputes and correction of data errors; or
- (d) An "RTM True-Up Statement," which is a statement issued at the end of the 180th day after the Operating Day.

(3) The Statement Recipient is responsible for accessing the Statement from the MIS Certified Area.

(4) To issue an RTM Settlement Statement, ERCOT may use estimated, disputed, or calculated meter data.

(5) ERCOT shall create an RTM Initial Statement, RTM Final Statement, and RTM True-Up Statement for each Operating Day.

(6) ERCOT may create an RTM Resettlement Statement for any Operating Day, depending on the criteria set forth in Section 9.5.6, RTM Resettlement Statement. When actual validated data is available and all of the Settlement and billing disputes raised by Statement Recipients in accordance with Section 9.14.4, ERCOT Processing of Disputes, during the validation process have been resolved, ERCOT shall recalculate the amounts payable and receivable by the affected RTM Statement Recipients, as described in Section 9.5.6.

(7) Each RTM Settlement Statement must denote:

- (a) Operating Day;
- (b) The Statement Recipient's name;
- (c) The ERCOT identifier (settlement identification number issued by ERCOT);
- (d) Status of the statement (Initial, Final, Resettlement, or True-Up);
- (e) Statement version number;
- (f) Unique statement identification code; and
- (g) Charge Types settled.

(8) A Settlement Statement for the RTM must break the fees down by Charge Type into the appropriate 15-minute or one-hour Settlement Interval for that type.

(9) An RTM Settlement Statement must have a summary page of the corresponding detailed documentation.

9.5.3 Real-Time Market Settlement Charge Types

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement "Charge Types" are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section 5.7.5, RUC Clawback Payment;

(g) Section 5.7.6, RUC Decommitment Charge;

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

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

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

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Payment;

(o) Section 6.6.3.8, Real-Time High Dispatch Limit Override Energy Charge;

(p) Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG);

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

(r) Section 6.6.5.1.1.1, Base Point Deviation Charge for Over Generation;

(s) Section 6.6.5.1.1.2, Base Point Deviation Charge for Under Generation;

(t) Section 6.6.5.2, IRR Generation Resource Base Point Deviation Charge;

(u) Section 6.6.5.4, Base Point Deviation Payment;

(v) Section 6.6.6.1, RMR Standby Payment;

(w) Section 6.6.6.2, RMR Payment for Energy;

(x) Section 6.6.6.3, RMR Adjustment Charge;

(y) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(z) Section 6.6.6.5, RMR Service Charge;

(aa) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(bb) Paragraph (2) of Section 6.6.7.1, Voltage Support Service Payments;

(cc) Paragraph (4) of Section 6.6.7.1;

(dd) Section 6.6.7.2, Voltage Support Charge;

(ee) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(ff) Section 6.6.8.2, Black Start Capacity Charge;

(gg) Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT;

(hh) Section 6.6.9.2, Charge for Emergency Power Increases;

(ii) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(jj) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(kk) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;

(ll) Paragraph (1)(a) of Section 6.7.1, Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Services Market (SASM) or Reconfiguration Supplemental Ancillary Services Market (RSASM);

(mm) Paragraph (1)(b) of Section 6.7.1;

(nn) Paragraph (1)(c) of Section 6.7.1;

(oo) Paragraph (1)(d) of Section 6.7.1;

(pp) Paragraph (1)(a) of Section 6.7.2, Payments for Ancillary Service Capacity Assigned in Real-Time Operations;

(qq) Paragraph (1)(b) of Section 6.7.2;

(rr) Paragraph (1)(a) of Section 6.7.2.1, Charges for Infeasible Ancillary Service Capacity Due to Transmission Constraints;

(ss) Paragraph (1)(b) of Section 6.7.2.1;

(tt) Paragraph (1)(c) of Section 6.7.2.1;

(uu) Paragraph (1)(d) of Section 6.7.2.1;

(vv) Paragraph (1)(a) of Section 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide;

(ww) Paragraph (1)(b) of Section 6.7.3;

(xx) Paragraph (1)(c) of Section 6.7.3;

(yy) Paragraph (1)(d) of Section 6.7.3;

(zz) Paragraph (2) of Section 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement;

(aaa) Paragraph (3) of Section 6.7.4;

(bbb) Paragraph (4) of Section 6.7.4;

(ccc) Paragraph (5) of Section 6.7.4;

(ddd) Paragraph (7) of Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge (Real-Time Ancillary Service Imbalance Amount);

(eee) Paragraph (7) of Section 6.7.5, (Real-Time Reliability Deployment Ancillary Service Imbalance Amount);

(fff) Paragraph (8) of Section 6.7.5, (Real-Time RUC Ancillary Service Reserve Amount);

(ggg) Paragraph (8) of Section 6.7.5, (Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount);

(hhh) Section 6.7.6, Real-Time Ancillary Service Imbalance Revenue Neutrality Allocation (Load-Allocated Ancillary Service Imbalance Revenue Neutrality Amount);

(iii) Section 6.7.6, (Load-Allocated Reliability Deployment Ancillary Service Imbalance Revenue Neutrality Amount);

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

(kkk) Section 9.16.1, ERCOT System Administration Fee.

[NPRR841, NPRR863, NPRR885, NPRR963, NPRR995, NPRR1012, NPRR1014, and NPRR1054: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR841, NPRR863, NPRR885, NPRR963, NPRR995, NPRR1014, or NPRR1054; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement "Charge Types" are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section 5.7.5, RUC Clawback Payment;

(g) Section 5.7.6, RUC Decommitment Charge;

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

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

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

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment;

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Charge;

(o) 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);

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

(q) Section 6.6.5.2, Set Point Deviation Charge for Over Generation;

(r) Section 6.6.5.2.1, Set Point Deviation Charge for Under Generation;

(s) Section 6.6.5.3, Controllable Load Resource Set Point Deviation Charge for Over Consumption;

(t) Section 6.6.5.3.1, Controllable Load Resource Set Point Deviation Charge for Under Consumption;

(u) Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge;

(v) Section 6.6.5.4, Set Point Deviation Payment;

(w) Section 6.6.5.5, Energy Storage Resource Set Point Deviation Charge for Over Performance;

(x) Section 6.6.5.5.1, Energy Storage Resource Set Point Deviation Charge for Under Performance;

(y) Section 6.6.6.1, RMR Standby Payment;

(z) Section 6.6.6.2, RMR Payment for Energy;

(aa) Section 6.6.6.3, RMR Adjustment Charge;

(bb) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(cc) Section 6.6.6.5, RMR Service Charge;

(dd) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(ee) Section 6.6.6.7, MRA Standby Payment;

(ff) Section 6.6.6.8, MRA Contributed Capital Expenditures Payment;

(gg) Section 6.6.6.9, MRA Payment for Deployment Event;

(hh) Section 6.6.6.10, MRA Variable Payment for Deployment;

(ii) Section 6.6.6.11, MRA Charge for Unexcused Misconduct;

(jj) Section 6.6.6.12, MRA Service Charge;

(kk) Paragraph (3) of Section 6.6.7.1, Voltage Support Service Payments;

(ll) Paragraph (5) of Section 6.6.7.1;

(mm) Section 6.6.7.2, Voltage Support Charge;

(nn) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(oo) Section 6.6.8.2, Black Start Capacity Charge;

(pp) Section 6.6.9.1, Payment for Emergency Operations Settlement;

(qq) Section 6.6.9.2, Charge for Emergency Operations Settlement;

(rr) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(ss) Section 6.6.11.1, Emergency Response Service Capacity Payments;

(tt) Section 6.6.11.2, Emergency Response Service Capacity Charge;

(uu) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(vv) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;

(ww) Section 6.7.4, Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations;

(xx) Section 6.7.5.2, Regulation Up Service Payments and Charges;

(yy) Section 6.7.5.3, Regulation Down Service Payments and Charges;

(zz) Section 6.7.5.4, Responsive Reserve Payments and Charges;

(aaa) Section 6.7.5.5, Non-Spinning Reserve Service Payments and Charges;

(bbb) Section 6.7.5.6, ERCOT Contingency Reserve Service Payments and Charges;

(ccc) Section 6.7.5.7, Real-Time Derated Ancillary Service Capability Payment;

(ddd) Section 6.7.5.8, Real-Time Derated Ancillary Service Capability Charge;

(eee) Section 6.7.6, Real-Time Ancillary Service Revenue Neutrality Allocation;

(fff) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time; and (ggg) Section 9.16.1, ERCOT System Administration Fee.

(2) In the event that ERCOT is unable to execute the Day-Ahead Market (DAM), ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for the following RTM Congestion Revenue Right (CRR) Settlement charges and payments:

(a) Section 7.9.2.4, Payments for FGRs in Real-Time; and

(b) Section 7.9.2.5, Payments and Charges for PTP Obligations with Refund in Real-Time.

9.5.4 RTM Initial Statement

(1) ERCOT shall issue an RTM Initial Statement for each Statement Recipient for a given Operating Day on the fifth day after the Operating Day, unless that fifth day is not a Business Day. If the fifth day is not a Business Day, then ERCOT shall issue the RTM Initial Statement on the next Business Day after the fifth day. Notwithstanding the above, if the fifth day after the Operating Day is on or prior to the Business Day on which Real-Time prices are final pursuant to paragraph (7) of Section 6.3, Adjustment Period and Real-Time Operations Timeline, then ERCOT shall issue the RTM Initial Statement on the first Business Day after the Real-Time prices are final.

9.5.5 RTM Final Statement

(1) ERCOT shall issue an RTM Final Statement for each Statement Recipient for a given Operating Day on the 55th day after the Operating Day, unless that 55th day is not a Business Day. If the 55th day is not a Business Day, then ERCOT shall issue the RTM Final Statement on the first Business Day after the 55th day.

(2) An RTM Final Statement will reflect differences to financial records generated on the previous Settlement Statement for the given Operating Day.

9.5.6 RTM Resettlement Statement

(1) ERCOT shall issue a RTM Resettlement Statement using corrected Settlement data due to resolution of Settlement and billing disputes. Any resettlement occurring after an RTM True-Up Statement has been issued must meet the same Interval Data Recorder (IDR) Meter Data Threshold requirements defined in Section 9.5.8, RTM True-Up Statement, and is subject to the same limitations for filing a dispute. Despite the preceding sentence, the ERCOT Board may, in its discretion, direct ERCOT to run a resettlement of any Operating Day, at any time, to address unusual circumstances.

(2) ERCOT shall issue a RTM Resettlement Statement for a given Operating Day due to errors other than errors in prices when:

(a) The total of all errors other than price errors results in an absolute value impact greater than 4% of the total RTM Statement amount for any single Statement Recipient for the Operating Day; and

(b) The impact to the Statement Recipient is greater than $400.00.

(3) Changes to meter data managed through a process other than a dispute or Alternative Dispute Resolution will not require evaluation of a resettlement defined in paragraph (2) above.

(4) For any Settlement and billing disputes resolved prior to issuance of the RTM Final Statement, ERCOT shall effect the dispute’s resolution on the RTM Final Statement for that Operating Day. If a dispute is submitted by 15 Business Days after the issuance of the RTM Initial Statement for an Operating Day and is not resolved on the RTM Final Statement, ERCOT will affect the dispute’s resolution on an RTM Resettlement Statement for that Operating Day. ERCOT shall issue such an RTM Resettlement Statement within a reasonable time after resolving the Settlement and billing dispute.

(5) ERCOT must effect the resolution of any dispute submitted more than 15 Business Days after the issuance of the RTM Initial Statement on the next available Resettlement or RTM True-Up statement for that Operating Day. For Settlement and billing disputes resolved under Section 9.14, Settlement and Billing Dispute Process, and submitted at least 20 Business Days before the scheduled date for issuance of the RTM True-Up Statement, ERCOT will include adjustments relating to the dispute on the RTM True-Up Statement. Resolved disputes must be included on the next available Settlement Invoice after ERCOT has issued the RTM True-Up Statement.

(6) ERCOT may not issue an RTM Resettlement Statement less than 20 days before a scheduled RTM Final Statement or RTM True-Up Statement for the relevant Operating Day. An RTM Resettlement Statement will reflect differences to financial records generated on the previous Settlement Statement for the given Operating Day.

(7) ERCOT may issue an RTM Resettlement Statement after the issuance of an RTM Final Statement in order to resolve approved disputes related to Section 5.6.5.2, RUC Make-Whole Payment and RUC Clawback Charge for Resources Receiving OSAs.

9.5.7 Notice of Resettlement for the Real-Time Market

(1) While maintaining confidentiality of all Market Participants, ERCOT shall send a Market Notice in conjunction with the resettlement, indicating the resettlement of a specific Operating Day and the date of issuance of the RTM Resettlement Statements. ERCOT shall include the following information in the notice of resettlement:

(a) Detailed description of reason(s) for resettlement;

(b) Affected Operating Days;

(c) Affected settlement Charge Types; and

(d) Total resettled amount, by Charge Type.

9.5.8 RTM True-Up Statement

(1) ERCOT shall use the best available Settlement data, as described in Section 9.5.2, Settlement Statements for the RTM, to produce an RTM True-Up Statement for each Statement Recipient for each given Operating Day.

(2) ERCOT shall issue RTM True-Up Statements 180 days following the Operating Day, if ERCOT has received and validated usage data from at least 99% of the total number of Electric Service Identifiers (ESI IDs) with a BUSIDRRQ Load Profile Type code and if ERCOT has received and validated usage data from at least 90% of the total number of ESI IDs with a BUSIDRRQ Load Profile Type code from each Meter Reading Entity (MRE) representing at least 20 Interval Data Recorder (IDR) ESI IDs (IDR Meter Data Threshold). If the above conditions have not been met, then ERCOT shall issue RTM True-Up Statements as soon as the IDR Meter data becomes available for that Operating Day. If no RTM True-Up Statement has been issued 365 days after the Operating Day, then ERCOT shall issue a RTM True-Up Statement for that Operating Day. If any RTM True-Up Statement issuance date does not fall on a Business Day, then the RTM True-Up Statement must be issued by the end of the next Business Day after the RTM True-Up Settlement date.

(3) An RTM True-Up Statement will reflect differences to financial records generated on the previous Settlement Statement for the given Operating Day.

9.5.9 Notice of True-Up Settlement Timeline Changes for the Real-Time Market

(1) If the IDR Meter Data Threshold has not been met by the 180th day after the Operating Day (or, if the 180th day is not a Business Day, by the next day thereafter that is a Business Day), then ERCOT shall send a Market Notice about the delay of any RTM True-Up Statement issuance indicating the IDR Meter Data Threshold has not been met.

(2) For any delayed RTM True-Up Statement, ERCOT shall send a Market Notice indicating that it will issue an RTM True-Up Statement for a specific Operating Day within two Business Days after discovering the delay. As soon as practicable, ERCOT shall send a Market Notice with the revised date on which the delayed RTM True-Up Statement will be issued.

9.5.10 Confirmation for the Real-Time Market

(1) It is the responsibility of each Statement Recipient to notify ERCOT if a Settlement Statement for the RTM is not available on the MIS Certified Area on the date specified for posting of that Settlement Statement in the Settlement Calendar. Each Settlement

Statement for the RTM is deemed to have been available on the posting date specified on the Settlement Calendar, unless it notifies ERCOT to the contrary. If ERCOT receives notice that a Settlement Statement is not available, ERCOT shall make reasonable attempts to provide the Settlement Statement to the Statement Recipient, and ERCOT shall modify the Settlement and billing timeline accordingly for that Settlement Statement.

9.5.11 Validation of the True-Up Statement for the Real-Time Market

(1) The Statement Recipient is considered to have validated each RTM True-Up Statement unless it has filed a Settlement and billing dispute or reported an exception within ten Business Days after the RTM True-Up Statement has been posted on the MIS Certified Area.

9.5.12 Suspension of Issuing Settlement Statements for the Real-Time Market

(1) The ERCOT Board may direct ERCOT to suspend the issuance of any Settlement Statement for the RTM to address unusual circumstances. Any proposal to suspend settlements must be presented to the Technical Advisory Committee (TAC) for review and comment, in a reasonable manner under the circumstances, before such suspension.

9.6 Settlement Invoices for the Day-Ahead Market and Real-Time Market

(1) ERCOT shall prepare Settlement Invoices on a net basis based on Day-Ahead Market (DAM) Statements, DAM Resettlement Statements, Real-Time Market (RTM) Initial Statements, RTM Final Statements, RTM True-Up Statements and RTM Resettlement Statements. ERCOT shall issue the Settlement Invoices on the same Business Day as the day that the DAM and RTM Statements are posted to the Market Information System (MIS) Certified Area. ERCOT will post the actual dates that it will issue the Settlement Invoices under Section 9.1.2, Settlement Calendar. The Market Participant to whom the Settlement Invoice is addressed ("Invoice Recipient") is either a net payee or net payor.

(2) Each Invoice Recipient shall pay any net debit and be entitled to receive any net credit shown on the Settlement Invoice on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit or credit.

(3) ERCOT shall post Settlement Invoices on the MIS Certified Area. The Invoice Recipient is responsible for accessing the Settlement Invoice on the MIS Certified Area once posted by ERCOT.

(4) Settlement Invoice items must be grouped by DAM, DAM Resettlement, RTM Initial, RTM Final, RTM Resettlement, and RTM True-Up categories and must be sorted by Operating Day within each category. Settlement Invoices must contain the following information:

(a) The Invoice Recipient’s name;

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

(c) Net Amount Due/Payable – the aggregate summary of all charges owed by or due to the Invoice Recipient;

(d) Time Periods – the time period covered for each line item;

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

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

(g) Statement Reference – an identification code used to reference each Settlement Statement invoiced;

(h) Payment Date and Time – the date and time that Invoice amounts are to be paid or received;

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

(j) Overdue Terms – the terms that would be applied if payments were received late.

9.7 Payment Process for the Settlement Invoices

(1) Payments for the Settlement Invoices are due on a Business Day and Bank Business Day basis in a two-day, two-step process as detailed below.

9.7.1 Invoice Recipient Payment to ERCOT for the Settlement Invoices

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

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

9.7.2 ERCOT Payment to Invoice Recipients for the Settlement Invoices

(1) Subject to the availability of funds as discussed in paragraph (2) below, ERCOT must pay Settlement Invoices with funds owed to an Invoice Recipient by 1700 on the next Bank Business Day after payments are due for that Settlement Invoice under Section 9.7.1, Invoice Recipient Payment to ERCOT for the Settlement Invoices, subject to ERCOT's right to withhold payments for any reason set forth in these Protocols or as a matter of law, unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit to each Invoice Recipient for same day value the amounts determined by ERCOT to be available for payment to that Invoice Recipient under paragraph (d) of Section 9.19, Partial Payments by Invoice Recipients.

9.7.3 Enforcing the Financial Security of a Short-Paying Invoice Recipient

(1) ERCOT shall make reasonable efforts to enforce the Financial Security of the short-paying Invoice Recipient (pursuant to Section 16.11.6, Payment Breach and Late Payments by Market Participants) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its Financial Security under Section 16, Registration and Qualification of Market Participants.

(2) ERCOT shall provide to all Market Participants payment details on all short payments and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the Invoice.

9.8 CRR Auction Award Invoices

(1) ERCOT shall prepare invoices for each Congestion Revenue Right (CRR) Auction (CRR Auction Invoice) on a net basis. Invoices must be issued on the first Business Day following the completion of a CRR Auction on the date specified in the Settlement Calendar. For each CRR Auction Invoice, the CRR Account Holder to whom the Invoice is addressed ("Invoice Recipient") is either a net payee or net payor. The Invoice Recipient is responsible for accessing the CRR Auction Invoice on the Market Information System (MIS) Certified Area once posted by ERCOT.

(2) Each Invoice Recipient shall pay any net debit and be entitled to receive any net credit shown on the CRR Auction Invoice on the payment due date. Payments for CRR Auction Invoices are due on the applicable payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the payment.

(3) ERCOT shall post on the MIS Certified Area for each Invoice Recipient a CRR Auction Invoice based on CRR Auction charges and payments as set forth in:

(a) Section 7.5.6.1, Payment of an Awarded CRR Auction Offer;

(b) Section 7.5.6.2, Charge of an Awarded CRR Auction Bid; and

(c) Section 7.5.6.3, Charge of PCRRs Pertaining to a CRR Auction.

(d) Section 7.7, Point-to-Point (PTP) Option Award Charge.

(4) CRR Auction Invoices must contain the following information:

(a) The Invoice Recipient's name;

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

(c) Net Amount Due/Payable – the aggregate summary of all charges owed to or due from the Invoice Recipient summarized by CRR Auction;

(d) Time Period – the CRR Auction for which the Invoice is generated;

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

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

(g) Product Description – a description of each product awarded in, sold in, or allocated before the CRR Auctions, or of any applicable charge;

(h) Payment Date – the date and time that Invoice amounts are to be paid or received; and

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

9.9 Payment Process for CRR Auction Invoices

(1) Payments for the Congestion Revenue Right (CRR) Auction are due on a Business Day and Bank Business Day basis in a two-day, two-step process as detailed below.

9.9.1 Invoice Recipient Payment to ERCOT for the CRR Auction

(1) The payment due date and time for the CRR Auction Invoice, with funds owed by an Invoice Recipient, is 1700 on the third Bank Business Day after the CRR Auction Invoice

date, unless third Bank Business Day is not a Business Day. If the third Bank Business Day is not a Business Day, the payment is due by 1700 on the next Bank Business Day after the third Bank Business Day that is also a Business Day.

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

(3) All CRR Auction Invoices must be paid in full on the Invoice due date.

9.9.2 ERCOT Payment to Invoice Recipients for the CRR Auction

(1) CRR Auction Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next day that is both a Business Day and a Bank Business Day after the day that payments are due for that CRR Auction Invoice under Section 9.9.1, Invoice Recipient Payment to ERCOT for the CRR Auction, subject to ERCOT's right to withhold payments under Section 16, Registration and Qualification of Market Participants or pursuant to the common law.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each Invoice Recipient for same day value the amounts owed to each Invoice Recipient.

9.9.3 Enforcing the Security of a Short-Paying CRR Auction Invoice Recipient

(1) ERCOT shall make reasonable efforts to enforce the security of the short-paying Invoice Recipient (pursuant to Section 16.11.6, Payment Breach and Late Payments by Market Participants) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its security under Section 16, Registration and Qualification of Market Participants.

9.10 CRR Auction Revenue Distribution Invoices

(1) ERCOT shall prepare Invoices for Congestion Revenue Right (CRR) Auction Revenue Distribution (CARD) on a monthly basis on the first Business Day following the Real-Time Market (RTM) Initial Settlement posting of the last day of the month on the date specified in the Settlement Calendar.

(2) ERCOT shall true up the distribution of monthly CRR Auction revenues by posting additional Settlement Invoices on the first Business Day following the RTM Final Settlement posting of the last day of the month on the date specified in the Settlement Calendar. A trued up CARD Invoice will reflect differences to financial records generated on the previous CARD Invoice for a given month.

(3) For each cycle, the Market Participant to whom the CARD Invoice is addressed ("Invoice Recipient") is either a payee or payor. The Invoice Recipient is responsible for accessing

the CARD Invoice on the Market Information System (MIS) Certified Area once posted by ERCOT.

(4) Each Invoice Recipient shall pay any debit and be entitled to receive any credit shown on the CARD Invoice on the payment due date. Payments for CARD Invoices are due on the applicable payment due date whether or not there is any Settlement and billing dispute regarding the amount of the payment.

(5) ERCOT shall post on the MIS Certified Area for each Invoice Recipient a CARD Invoice based the calculations located:

(a) Section 7.5.6.4, CRR Auction Revenues; and

(b) Section 7.5.7, Method for Distributing CRR Auction Revenues.

(6) CARD Invoices must contain the following information:

(a) The Invoice Recipient’s name;

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

(c) Net Amount Due/Payable – the aggregate summary of all charges owed to or due from the Invoice Recipient summarized by CRR Auction revenue month;

(d) Time Period – the CRR Auction revenue month for which the Invoice is generated, including Initial or Final distribution;

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

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

(g) Payment Date – the date and time that Invoice amounts are to be paid or received; and

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

9.11 Payment Process for CRR Auction Revenue Distribution

(1) Payments for Congestion Revenue Right (CRR) Auction Revenue Distribution (CARD) Invoices are due on a Business Day and Bank Business Day basis in a two-day, two-step process as detailed below.

9.11.1 Invoice Recipient Payment to ERCOT for CRR Auction Revenue Distribution

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

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

9.11.2 ERCOT Payment to Invoice Recipients for CRR Auction Revenue Distribution

(1) CARD Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next day that is both a Business Day and a Bank Business Day after the day that payments are due for that CARD Invoice under Section 9.11.1, Invoice Recipient Payment to ERCOT for CRR Auction Revenue Distribution, subject to ERCOT's right to withhold payments under Section 16 and pursuant to common law.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each Invoice Recipient for same day value, the amounts owed to each Invoice Recipient.

9.11.3 Partial Payments by Invoice Recipients for CRR Auction Revenue Distribution

(1) If at least one Invoice Recipient owing funds does not pay its CARD Invoice in full (short-pay), ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient before any payments owed by ERCOT for that month's distribution of CRR Auction revenues is due to be paid to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available security pledged to ERCOT by each short-paying Invoice Recipient that did not pay the amount due under paragraph (a) above. If the amount of any such draw is greater than the amount of the short-paying Invoice Recipient's cash collateral held in excess of that required to cover its Total Potential Exposure (TPE) ("Excess Collateral"), then a draw on available security for a short-paying Invoice Recipient shall be considered a Late Payment for purposes of Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(c) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT to a short-paying Invoice Recipient against amounts not paid by that Invoice Recipient and ERCOT shall apply the amount offset or recouped to cover payment shortages by that Invoice Recipient.

(d) If, after taking the actions set forth in paragraphs (a), (b) and (c), above, ERCOT still does not have sufficient funds to pay all amounts that it owes to CARD Invoice Recipients in full, ERCOT shall reduce payments to all CARD Invoice Recipients owed monies from ERCOT. The reductions shall be based on a pro rata basis of monies owed to each CARD Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short payments and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the CARD Invoice.

9.11.4 Enforcing the Security of a Short-Paying CARD Invoice Recipient

(1) ERCOT shall make reasonable efforts to enforce the security of the short-paying Invoice Recipient (pursuant to Section 16.11.6, Payment Breach and Late Payments by Market Participants) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its security under Section 16, Registration and Qualification of Market Participants.

9.12 CRR Balancing Account Invoices

(1) ERCOT shall prepare Invoices for the Congestion Revenue Right (CRR) Balancing Account (CRRBA) on a monthly basis on the first Business Day following the Real-Time Market (RTM) Initial Settlement posting of the last day of the month on the date specified in the Settlement Calendar.

(2) ERCOT shall true up the distribution of monthly the CRRBA by posting additional Settlement Invoices on the first Business Day following the RTM Final Settlement posting of the last day of the month on the date specified in the Settlement Calendar. A trued up CRRBA Invoice will reflect differences to financial records generated on the previous CRRBA Invoice for a given month.

(3) ERCOT shall prepare resettlement Invoices in the event that the balance in the CRRBA for the month changes due to a Day-Ahead Market (DAM) resettlement after the initial balancing account Invoices for that month have been posted as specified in the Settlement Calendar. The Monthly Load Ratio Share (MLRS) as described in Section 7.9.3.5, CRR Balancing Account Closure, used for the resettlement CRRBA Invoice will be the same one used for the most recently posted balancing account Invoices. A resettlement CRRBA Invoice will reflect differences to financial records generated on the previous CRRBA Invoice for a given month.

(4) For each Invoice cycle, the Market Participant to whom the CRRBA Invoice is addressed ("Invoice Recipient") is a payee. The Invoice Recipient is responsible for accessing the CRRBA Invoice on the Market Information System (MIS) Certified Area once posted by ERCOT.

(5) ERCOT shall post on the MIS Certified Area for each Invoice Recipient a CRRBA Invoice based on the calculations located in Sections 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners, and 7.9.3.5.

(6) CRRBA Invoices must contain the following information:

(a) The Invoice Recipient's name;

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

(c) Net Amount Payable – the aggregate summary of all amounts owed to the Invoice Recipient summarized by month;

(d) Time Period – the time period covered for each line item;

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

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

(g) Payment Date – the date and time that Invoice amounts are to be received.

(7) Each Invoice Recipient shall receive any credit shown on the CRRBA Invoice on the payment due date. Credit shown on the CRRBA Invoice will be paid on due date whether or not there is any Settlement and billing dispute regarding the amount of the payment.

9.13 Payment Process for the CRR Balancing Account

9.13.1 Payment Process for the Initial CRR Balancing Account

(1) Payments for the Congestion Revenue Right (CRR) Balancing Account (CRRBA) are due on a Business Day and Bank Business Day basis in a one-day, one-step process, as detailed below.

(a) By 1700 on the first day that is both a Business Day and a Bank Business Day following the due date of the Settlement Invoice that includes the Real-Time Market (RTM) Initial Settlement Statement for the last day of the month and subject to ERCOT's right to withhold payments under Section 16, Registration and Qualification of Market Participants, and pursuant to common law, ERCOT shall pay on a net credit shown on the CRRBA Invoice based on amounts due:

(i) To each short-paid CRR Owner a monthly refund from the positive balance in the CRRBA, with the amount paid to each CRR Owner as calculated in Section 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners; and

(ii) To each Qualified Scheduling Entity (QSE), any remaining positive balance in the CRRBA, with the amount paid to each QSE as calculated in Section 7.9.3.5, CRR Balancing Account Closure.

(b) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each CRR Owner or QSE, for same day value, the amounts determined by ERCOT to be available for payment.

9.13.2 Payment Process for Resettlement of the CRR Balancing Account

(1) In the event that a resettlement CRRBA Invoice is required, payments for the resettlement CRRBA Invoice are due on a Business Day and Bank Business Day basis in a two-day, two-step process as detailed below in Section 9.13.2.1, Invoice Recipient Payment to ERCOT for Resettlement of the CRR Balancing Account.

9.13.2.1 Invoice Recipient Payment to ERCOT for Resettlement of the CRR Balancing Account

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

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

9.13.2.2 ERCOT Payment to Invoice Recipients for Resettlement of the CRR Balancing Account

(1) Resettlement CRRBA Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next day that is both a Business Day and a Bank Business Day after the day that payments are due for that resettlement CRRBA Invoice as described in paragraph (1) of Section 9.13.2.1, Invoice Recipient Payment to ERCOT for Resettlement of CRR Balancing Account. The Invoice Recipient payment to ERCOT for resettlement of the CRRBA is subject to ERCOT’s right to withhold payments under Section 16, Registration and Qualification of Market Participants.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit to each Invoice Recipient for same day value, the amounts owed to each Invoice Recipient.

9.13.2.3 Partial Payments by Invoice Recipients for Resettlement of CRR Balancing Account

(1) If at least one Invoice Recipient owing funds does not pay its resettlement CRRBA Invoice in full (short-pay), ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient before any payments owed by ERCOT for that month's distribution of resettlement CRRBA revenues is due to be paid to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available security pledged to ERCOT by each short-paying Invoice Recipient that did not pay the amount due under paragraph (a) above. If the amount of any such draw is greater than the amount of the short-paying Invoice Recipient's cash collateral held in excess of that required to cover its Total Potential Exposure (TPE) ("Excess Collateral"), then a draw on available security for a short-paying Invoice Recipient shall be considered a Late Payment for purposes of Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(c) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT to a short-paying Invoice Recipient against amounts not paid by that Invoice Recipient and ERCOT shall apply the amount offset or recouped to cover payment shortages by that Invoice Recipient.

(d) If, after taking the actions set forth in paragraphs (a), (b) and (c) above, ERCOT still does not have sufficient funds to pay all amounts that it owes to resettlement CRRBA Invoice Recipients in full, ERCOT shall reduce payments to all resettlement CRRBA Invoice Recipients owed monies from ERCOT. The reductions shall be based on a pro rata basis of monies owed to each resettlement CRRBA Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short payments and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the resettlement CRRBA Invoice.

9.14 Settlement and Billing Dispute Process

9.14.1 Data Review, Validation, Confirmation, and Dispute of Settlement Statements

(1) Settlement Statement Recipients and Invoice Recipients for the Day-Ahead Market (DAM), Real-Time Market (RTM), and Congestion Revenue Right (CRR) Auction are responsible for reviewing their Settlement Statements and Settlement Invoices to verify the accuracy of the data used to produce them. Other than disputes related to resettlement arising from a completed Alternative Dispute Resolution (ADR) proceeding, Settlement Statement Recipients and Invoice Recipients must submit any dispute related to a Settlement Statement or Settlement Invoice pursuant to this Section. A Market Participant who wishes to dispute a resettlement arising from a completed ADR proceeding must appeal ERCOT's disposition of that proceeding in accordance with paragraph (3) of Section 20.9, Resolution of Alternative Dispute Resolution Proceedings and Notification to Market Participants.

9.14.2 Notice of Dispute

(1) A Settlement Statement Recipient may dispute items or calculations in the most recently issued Settlement Statement for an Operating Day, except as limited for RTM True-Up Statements in paragraph (3) below. The dispute will apply to the Operating Day in question, not to the associated Settlement Statement. The Market Participant must enter the Settlement and billing dispute electronically through the ERCOT dispute tool provided on the Market Information System (MIS) Certified Area. In processing disputes under this Section, ERCOT will analyze the latest Settlement Statement issued.

(2) An Invoice Recipient may dispute elements of an Invoice that are not the result of a Settlement Statement that are contained on the Invoice. The Invoice Recipient must file the Invoice dispute within ten Business Days of the date on which ERCOT posted the Invoice.

(3) The Settlement Statement Recipient is deemed to have validated each RTM True-Up Statement or Resettlement Statement arising from the True-Up Statement unless it has raised a Settlement and billing dispute or reported an exception within ten Business Days of the date on which ERCOT issued the Settlement Statement. With respect to an RTM True-Up Statement or any subsequent Resettlement Statement after ERCOT issued the True-Up Statement, ERCOT will consider only Settlement and billing disputes associated with incremental changes between the RTM True-Up Statement or Resettlement Statement, and the most recent previous Settlement Statement for that Operating Day. The Settlement Statement Recipient may recover only the amounts associated with the incremental monetary change between the prior statement and the statement from which the dispute arose. ERCOT shall reject late-filed Settlement and billing disputes. Once the deadline for filing a dispute has passed, the RTM True-Up Statement binds the Settlement Statement Recipient to which it relates unless ERCOT issues a subsequent Resettlement Statement pursuant to this Section.

(4) ERCOT shall reject Settlement and billing disputes for a given Operating Day during the 20 Business Days before the scheduled date for issuance of the RTM True-Up Statement for that Operating Day.

(5) However, to the extent a disputing party claims that the Settlement or billing dispute relates to information made available under Section 1.3.3, Expiration of Confidentiality, the disputing party must register the Settlement and billing dispute with ERCOT by electronic means within 60 days after the date the information became available. All communication to and from ERCOT concerning disputes must be made through either the MIS Certified Area or other electronic communication.

(6) The Settlement Statement Recipient is deemed to have validated each DAM Settlement or Resettlement Statement unless it has raised a Settlement and billing dispute or reported an exception within ten Business Days of the date on which ERCOT issued the Settlement or Resettlement Statement. With respect to a DAM Resettlement Statement, ERCOT will consider only Settlement and billing disputes associated with incremental changes between the DAM Resettlement Statement and the most recent previous Settlement Statement for that Operating Day. The Settlement Statement Recipient may recover only the amounts associated with the incremental monetary change between the prior statement and the statement from which the dispute arose. ERCOT shall reject late-filed Settlement and billing disputes. Once the deadline for filing a dispute has passed, a DAM Statement binds the Settlement Statement Recipient to which it relates unless ERCOT issues a subsequent Resettlement Statement.

(7) A CRR Auction Invoice, CRR Auction Revenue Distribution (CARD) Invoice, or CRR Balancing Account (CRRBA) Invoice Recipient may dispute elements of an Invoice that are contained on the Invoice. The Invoice Recipient must file the CRR Invoice dispute within ten Business Days of the date on which ERCOT posted the Invoice.

9.14.3 Contents of Notice

(1) ERCOT shall reject a dispute that does not contain the data elements listed in this Section.

(2) ERCOT shall provide automatic field population techniques or drop-down boxes for appropriate data elements below. The notice of Settlement and billing dispute must state clearly:

(a) Disputing Entity;

(b) Dispute contact person(s);

(c) Dispute contact information;

(d) Operating Day or Invoice date in dispute;

(e) Charge Type;

(f) Time period in dispute;

(g) Amount in dispute;

(h) Settlement and billing dispute type; and

(i) Reasons for the dispute.

(3) Each Settlement and billing dispute must specify an Operating Day or Invoice date and a Charge Type. If a condition causing a dispute affects multiple Operating Days or Charge Types, a Settlement Statement Recipient or Invoice Recipient may file a dispute form for each Charge Type for one or more Operating Days affected on a single dispute that are all in the same calendar month.

(4) A Settlement Statement Recipient or Invoice Recipient may pursue the dispute through any process provided by ERCOT for resolving differences in Settlement determinants.

(5) Forms for entering a Settlement and billing dispute must be provided on the MIS Certified Area.

(6) The Market Participant must submit the Settlement and billing dispute to ERCOT with sufficient evidence to support the claim.

(7) The Market Participant must submit a dispute using an ERCOT-approved electronic format. ERCOT shall provide a dispute tracking identifier to the Settlement Statement Recipient or Invoice Recipient.

9.14.4 ERCOT Processing of Disputes

(1) ERCOT shall process disputes in accordance with this Section, Section 9.14.2, Notice of Dispute, and the required data in Section 9.14.3, Contents of Notice.

(2) If ERCOT requires additional data to resolve the dispute, ERCOT shall send the Settlement Statement Recipient or Invoice Recipient a list of the required additional data within seven Business Days of the date the dispute was filed. The Settlement Statement Recipient or Invoice Recipient shall respond with the entire set of required data within five Business Days of ERCOT's request or by a date agreed upon by ERCOT and the Market Participant that is no later than eight Business Days prior to the posting of the True-Up Settlement Statement for the disputed Operating Day. If ERCOT does not receive the data within that time frame, ERCOT shall deny the dispute.

(3) On each Business Day, ERCOT shall issue an aggregated Settlement and billing dispute resolution report on the MIS Secure Area containing information related to all disputes that are not yet closed or that have been closed recently. Additionally, on each Business Day and for each Settlement Statement Recipient or Invoice Recipient, ERCOT shall issue a report on the MIS Certified Area containing the status of each submitted dispute. The report shall identify the disputed charge type(s), status of the dispute, resolution and

resolution date, if applicable, and a financial impact in dollars of the dispute as submitted by disputing Entity.

(4) ERCOT shall make all reasonable attempts to complete all RTM Settlement and billing disputes submitted within 15 Business Days of the issuance of the RTM Initial Statement in time for inclusion on the RTM Final Statement for the relevant Operating Day.

(5) All complete disputes of the DAM received within ten Business Days after ERCOT posts that day's DAM Settlement Statement shall be included in a Resettlement of the DAM Operating Day under Section 9.2.5, DAM Resettlement Statement.

(6) For Settlement and billing disputes requiring complex research or additional time for resolution, ERCOT shall notify the Invoice Recipient or Settlement Statement Recipient of the length of time expected to research and resolve those disputes and, if ERCOT grants a portion or all of the dispute, ERCOT shall post the necessary adjustments on the next available Settlement Statement for the Operating Day.

(7) Settlement Statement Recipients or Invoice Recipients have the right to proceed to the ADR process in Section 20, Alternative Dispute Resolution Procedure, for filed disputes that cannot be resolved through the Settlement and billing dispute process outlined in Section 9.14, Settlement and Billing Dispute Process.

(8) All complete disputes of the CRR Market received within ten Business Days after ERCOT posts that day's CRR Settlement Statement shall be resolved as soon as practicable.

9.14.4.1 Status of Dispute

(1) ERCOT will assign a status to each dispute as defined in the following Sections.

9.14.4.1.1 Not Started

(1) The status of a Settlement and billing dispute will initially be set to "Not Started" when the Market Participant enters the dispute into the ERCOT dispute resolution system.

9.14.4.1.2 Open

(1) The status of a Settlement and billing dispute is set to "Open" when the Settlement Statement or Invoice Recipient submits a dispute to ERCOT and ERCOT begins the resolution process.

9.14.4.1.3 Closed

(1) When the status is set to "Closed," no updates or additions are permitted to the dispute record. The status of the dispute is "Closed" when one of the following conditions occurs:

(a) If, after 45 days from receiving notice of a denied dispute, the Settlement Statement Recipient or Invoice Recipient does not begin the ADR process, ERCOT will close the dispute.

(b) If ERCOT grants a Settlement and billing dispute, ERCOT will close the dispute no sooner than the date ERCOT publishes the next available Settlement Statement or Invoice for the associated Operating Day.

(c) If ERCOT grants a dispute with exceptions, ERCOT will close the dispute no sooner than ten Business Days after ERCOT publishes the resolution. If the Settlement Statement Recipient or Invoice Recipient disagrees with ERCOT's exceptions, ERCOT will close dispute upon completion of further investigation and resolution in accordance with Section 9.14.4.2.3, Granted with Exceptions.

9.14.4.1.4 Rejected

(1) ERCOT shall set the status of a Settlement and billing dispute to "Rejected" when one of the following circumstances is met:

(a) The dispute is filed late, unless filed in accordance with paragraph (5) of Section 9.14.2, Notice of Dispute, due to an expiration of confidentiality as defined under Section 1.3.3, Expiration of Confidentiality.

(b) During the 20 Business Days before the scheduled date for issuance of the RTM True-Up Statement for that Operating Day.

(c) The dispute does not contain the required data as set forth in Section 9.14.3, Contents of Notice. ERCOT shall provide specific Protocol language supporting the reasons that data provided by the Settlement Statement Recipient or Invoice Recipient is insufficient. If able to do so timely, an Invoice Recipient or Settlement Statement Recipient may resubmit the dispute with additional information under Section 9.14.2. Once the Settlement Statement Recipient or Invoice Recipient submits the required information and ERCOT determines the Settlement and billing dispute is timely and complete, the dispute status is changed to "Open."

9.14.4.1.5 Withdrawn

(1) A Market Participant who submitted a Settlement and billing dispute may withdraw that dispute at any time. If withdrawal occurs, the Dispute status is set to "Withdrawn" and any research and resolution activities on that dispute will cease.

9.14.4.1.6 ADR

(1) Requests for ADR shall be considered Protected Information in accordance with paragraph (1)(ff) of Section 1.3.1.1, Items Considered Protected Information, and Section 20, Alternative Dispute Resolution Procedure. As soon as practicable after ERCOT receives a written request for ADR pursuant to Section 20.4, Initiation of ADR Proceedings, ERCOT shall post a Settlement and billing dispute status of "ADR" to the aggregated Settlement and billing dispute resolution report on the MIS Secure Area. The dispute will remain in the ADR status as long as the Market Participant has an active ADR. At the end of the ADR process, ERCOT shall post a Settlement and billing dispute status of "Closed" to the aggregated Settlement and billing dispute resolution report on the MIS Secure Area.

9.14.4.2 Resolution of Dispute

(1) Each resolved dispute will have a resolution as defined in the following Sections.

9.14.4.2.1 Denied

(1) If ERCOT concludes that the Settlement Statement or Invoice is correct, ERCOT shall deny the Settlement and billing dispute. ERCOT shall notify the Settlement Statement Recipient or Invoice Recipient when it denies a Settlement and billing dispute and provide the Settlement Statement Recipient or Invoice Recipient the reasons and supporting data for the denial, while maintaining the confidentiality of Protected Information.

(2) If the Settlement Statement Recipient or Invoice Recipient is not satisfied with the outcome of a denied Settlement and billing dispute, the Settlement Statement Recipient or Invoice Recipient may proceed to ADR as described in Section 20, Alternative Dispute Resolution Procedure.

9.14.4.2.2 Granted

(1) When ERCOT determines that the disputed Settlement Statement or Invoice are in error as alleged in the Settlement and billing dispute, ERCOT shall grant the Settlement and billing dispute and notify the Settlement Statement or Invoice Recipient of the resolution and provide it the reasons and supporting data for resolution, while maintaining the confidentiality of Protected Information. ERCOT shall make available to all other

Settlement Statement or Invoice Recipients the financial impact, as submitted by disputing Entity, on the Settlement and billing dispute resolution report per paragraph (3) of Section 9.14.4, ERCOT Processing of Disputes. Upon resolution of the issue, ERCOT shall process the dispute's resolution on the next available Settlement Statement for the affected Operating Day.

9.14.4.2.3 Granted with Exceptions

(1) ERCOT may determine that a Settlement and billing dispute is "Granted with Exceptions" when ERCOT deems the basis for the Settlement and billing dispute partially correct. ERCOT shall provide the exception information to the Settlement Statement or Invoice Recipient. ERCOT shall notify the Settlement Statement or Invoice Recipient of the "Granted with Exceptions" resolution and shall provide the reasons and supporting data, while maintaining the confidentiality of Protected Information for the resolution. ERCOT shall make available to all other Settlement Statement or Invoice Recipients the financial impact, as submitted by the disputing Entity, on the Settlement and billing dispute resolution report per paragraph (3) of Section 9.14.4, ERCOT Processing of Disputes. The Settlement Statement or Invoice Recipient of the dispute granted with exceptions shall acknowledge receipt of the notice within ten Business Days after ERCOT publishes the resolution as "Granted with Exceptions". The acknowledgement must indicate acceptance or rejection of the documented exceptions to the granting of the dispute. If the Settlement Statement or Invoice Recipient does not timely reject the dispute outcome, it shall be deemed accepted. If the Market Participant accepts the exceptions, ERCOT shall post the necessary adjustments on the next available Settlement Statement for the affected Operating Day.

(2) If a Settlement Invoice or Statement Recipient rejects the outcome of a dispute "Granted with Exceptions," ERCOT must investigate the dispute further. ERCOT must include the granted portion of the dispute on the next Settlement Statement for the affected Operating Day. After further investigation, if ERCOT subsequently grants the Settlement and billing dispute, ERCOT must process the dispute on the next available Settlement Statement for the affected Operating Day. If exceptions to the dispute still exist, the Settlement Statement or Invoice Recipient may either accept the dispute for resolution as "Granted with Exceptions" or begin ADR according to Section 20, Alternative Dispute Resolution Procedure.

9.14.5 Settlement of Emergency Response Service

(1) ERCOT shall post the settlement for each Emergency Response Service (ERS) type and Time Period in an ERS Contract Period 20 days after the final Settlement of the last Operating Day of the ERS Standard Contract Term is posted, as described in paragraph (1) of Section 9.5.5, RTM Final Statement. If the 20th day is not a Business Day, ERCOT will post the ERS Settlement on the next Business Day thereafter. All disputes for the Settlement of the ERS Contract Period are due ten Business Days after the date

that the ERS settlement was posted. ERCOT shall resolve any approved disputes upon resettlement of the ERS Contract Period, as described in paragraph (2) below.

(2) ERCOT shall post the resettlement for each ERS type and Time Period in an ERS Contract Period on the True-Up Settlement for the Operating Day on which the charge was first settled as described in paragraph (1) above. ERS disputes filed based on a change in Load after the True-Up Settlement will be approved only if the Qualified Scheduling Entity's (QSE's) Load changes by 10% or more. ERCOT shall resolve any approved ERS disputes no later than 30 Business Days after the date that the ERS resettlement was posted.

9.14.6 Disputes for Operations Decisions

(1) Settlement Statement or Invoice Recipients may not dispute a Settlement Statement or Invoice due to a decision made by ERCOT in its operation of the ERCOT System, unless the Market Participant alleged the decision violated these Protocols. Inquiries or disputes concerning such decisions, Protocols, or Operating Guides must be handled through the Protocol change process set forth in Section 21, Revision Request Process.

9.14.7 Disputes for RUC Make-Whole Payment for Fuel Costs

(1) If the actual price paid for delivered natural gas for a specific Resource during a Reliability Unit Commitment (RUC)-Committed Interval is greater than Fuel Index Price (FIP) adjusted by the proxy fuel adder, X, defined in the Verifiable Cost Manual (i.e., FIP * (1+X)), then the QSE may file a Settlement dispute for that Resource's RUC Make-Whole Payment. The maximum amount that may be recovered through this dispute process is the difference between the RUC Guarantee based on the actual price paid and the fuel price of FIP * (1+X). The QSE must provide documentation (invoices) that identifies intra-day, same-day, or spot market costs of natural gas consumed during the RUC-Committed Interval. Such documentation is necessary to justify recovery of natural gas costs, which is limited to the actual fuel amount (MMBtus) consumed during RUC-Committed Intervals. All documentation submitted by the QSE for natural gas costs incurred intra-day, same-day, or via spot market must show a nexus from the seller or distributor of natural gas products to the QSE, Resource Entity or Generation Entity as the ultimate buyer. The QSE must demonstrate that the seller or distributor has procured natural gas fuel intra-day, same-day, or via spot market. A Power Purchase or Tolling Agreement (PPA) filed as documentation of proof of fuel costs will not be accepted unless the PPA was signed prior to July 16, 2008, and is not between Affiliates, subsidiaries, or partners.

(2) If the actual price paid for the delivered fuel oil used to replace oil consumed during a RUC-Committed Interval is greater than Fuel Oil Price (FOP) adjusted by the proxy fuel adder, X, defined in the Verifiable Cost Manual (i.e., FOP * (1+X)), then the QSE may file a Settlement dispute for the Resource's RUC Make-Whole Payment. The maximum amount that may be recovered through this dispute process is the difference between the RUC Guarantee based on the actual price paid and the adjusted price, FOP * (1+X).

(3) If the QSE representing the Generation Resource made a Three-Part Supply Offer into the DAM based on FIP and had to run on fuel oil in a RUC-Committed Hour with an active Three-Part Supply Offer based on the adjusted FIP, the QSE may file a Settlement dispute to recover the difference between the RUC Guarantee based actual price paid for delivered fuel oil and the fuel price of FIP * (1+X).

(4) When filing a Settlement dispute under paragraph (2) or (3) above, the QSE must provide documentation (invoices) that identifies purchases of fuel oil by the QSE, Resource Entity, or Generation Entity to replace oil consumed for a RUC-Committed Interval. In addition, the QSE must provide proof that the Resource actually consumed fuel oil during the RUC-Committed Interval. Proof of actual consumption may be based on the Resource's technical specifications or flow meters as appropriate. Documentation of fuel oil purchases must show that these were made no later than seven Business Days after the end of the last consecutive RUC-Committed Interval. Replacement fuel oil costs are limited to the actual gallons/barrels of fuel oil consumed during RUC-Committed Intervals.

(5) ERCOT may, in its sole discretion, consider documentation types other than those specifically listed in paragraphs (1) and (4) above when offered by a QSE in support of its recovery of fuel costs for RUC deployments. For example, ERCOT may require the Resource input-output equation or average heat rate curve that allows for verification of fuel consumption for operation at and above Low Sustained Limit (LSL).

(6) When calculating the RUC Guarantee as described in paragraph (1), (2) or (3) above, the Startup Price per start (SUPR) and the Minimum-Energy Price (MEPR), as defined in paragraph (6) of Section 5.7.1.1, RUC Guarantee, will be set to the Startup Cap (SUCAP) and Minimum-Energy Cap (MECAP), respectively, utilizing the actual fuel price paid.

(7) In order to recover fuel costs above LSL for a RUC-Committed Interval, the QSE must also submit proof of the volume-weighted average actual price paid for fuel consumed by the Resource during a RUC-Committed Interval for generation above LSL. ERCOT will adjust the RUC Guarantee (RUCG) to include the additional fuel costs above LSL filed by the QSE.

[NPRR1140: Replace paragraph (7) above with the following upon system implementation:]

(7) In order to recover fuel costs above LSL for a RUC-Committed Interval, the QSE must also submit proof of the volume-weighted average actual price paid for fuel consumed by the Resource during a RUC-Committed Interval for generation above LSL.

9.14.8 Disputes for Settlement Application of Integrated Telemetry for Split Generation Resources

(1) Settlement and billing disputes related to application of integrated Real-Time telemetry of MW or MVAr from a Generation Resource that has been split to function as two or

more Split Generation Resources require a signed affidavit by all QSEs representing associated Split Generation Resources. Data values submitted with the affidavit must be integrated to the applicable Settlement Interval format related to the Settlement and billing charge type in dispute.

9.14.9 Incremental Fuel Costs for Switchable Generation Make-Whole Payment Disputes

(1) For the purposes of any Settlement and billing dispute submitted pursuant to paragraph (1)(c) of Section 6.6.12, Make-Whole Payment for Switchable Generation Resources Committed for Energy Emergency Alert (EEA), if the actual price paid for delivered natural gas for a specific Switchable Generation Resource (SWGR) for an instructed hour is greater than FIP plus the fuel adder, then the QSE may recover the fuel costs incurred for that SWGR in the Settlement and billing dispute. The QSE must provide documentation (invoices) that identifies intra-day costs of natural gas consumed. All documentation submitted by the QSE for natural gas costs incurred intra-day must show a nexus from the seller or distributor of natural gas products to the QSE, Resource Entity or Generation Entity as the ultimate buyer. The QSE must demonstrate that the seller or distributor has procured natural gas fuel intra-day.

(2) For the purposes of any Settlement and billing dispute submitted pursuant to paragraph (1)(c) of Section 6.6.12, if the actual price paid for the delivered fuel oil used to replace oil consumed for an instructed hour is greater than FOP plus the fuel adder, then the QSE may recover the fuel costs incurred for that SWGR in the dispute. The QSE must provide documentation that identifies purchases of fuel oil by the QSE, Resource Entity, or Generation Entity to replace oil consumed. In addition, the QSE must provide proof that the SWGR actually consumed fuel oil for the instructed hour. Proof of actual consumption may be based on the Resource's technical specifications or flow meters as appropriate. Documentation of fuel oil purchases must show that these were made no later than seven Business Days after the end of the last consecutive instructed hour.

(3) A QSE submitting documents for the recovery of RUC-related fuel costs other than those specifically discussed in paragraph (1) or (2) above must request to have such documents approved by the ERCOT Board during an Executive Session at the next regularly scheduled meeting of the ERCOT Board. If the ERCOT Board approves the inclusion of such documentation as proof of fuel purchases, the QSE must file an NPRR in accordance with Section 21, Revision Request Process, to add this category of documentation to the process for approval of Switchable Generation Make-Whole Payments.

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

(1) A Market Participant that has been directly impacted by an action or omission by ERCOT to resolve the DAM, as described in paragraph (4) of Section 4.1.2, Day-Ahead Process and Timing Deviations, may seek recovery by filing a Settlement and billing dispute as defined in Section 9.14. Where ERCOT determines that the Market Participant seeking

recovery has been directly impacted by such ERCOT action or omission, the following provisions apply:

(a) No resettlement of the DAM will occur as a result of a Market Participant's recovery under this Section;

(b) Where a Market Participant's submissions were not cleared in the DAM, ERCOT will establish a set of DAM Energy Bids, DAM Energy Offers, Ancillary Service Offers, and Point-to-Point (PTP) bids that would have cleared given the settled prices of the DAM;

(c) Startup Costs and minimum energy costs will not be considered for recovery;

(d) For linked offers of energy and Ancillary Services, the available capacity will be allocated to the offers that would have created the greatest value for the Market Participant seeking recovery;

(e) All impacted positions will be summed based on their positive or negative value with respect to Real-Time prices;

Day-Ahead Energy Sales Impact

$$\text{DAMSQSEAMT}_{q} = (-1) * \sum_{p} ((\text{DASPP}_{p} - \text{RTSPP}_{p}) * (1/4) * \text{DAES}_{q,\,p})$$

Day-Ahead Energy Purchase Impact

$$\text{DAMPQSEAMT}_{q} = (-1) * \sum_{p} ((\text{RTSPP}_{p} - \text{DASPP}_{p}) * (1/4) * \text{DAEP}_{q,\,p})$$

Day-Ahead Ancillary Services Sales Impact

$$\begin{aligned}\text{DAMASQSEAMT}_{q} = (-1) * \sum_{r} (& ((\text{MCPCRU}_{DAM} - \text{RUOPR}_{q,\,r,\,DAM}) * \text{PCRUR}_{q,\,r,\,DAM}) \\ & + ((\text{MCPCRD}_{DAM} - \text{RDOPR}_{q,\,r,\,DAM}) * \text{PCRDR}_{q,\,r,\,DAM}) \\ & + ((\text{MCPCRR}_{DAM} - \text{RROPR}_{q,\,r,\,DAM}) * \text{PCRRR}_{q,\,r,\,DAM}) \\ & + ((\text{MCPCNS}_{DAM} - \text{NSOPR}_{q,\,r,\,DAM}) * \text{PCNSR}_{q,\,r,\,DAM}))\end{aligned}$$

[NPRR903: Replace the formula for "Day-Ahead Ancillary Services Sales Impact" above with the following upon system implementation of NPRR863:]

Day-Ahead Ancillary Services Sales Impact

$$\mathrm{DAMASQSEAMT}_{q} = (-1) * \sum_{r} (((\mathrm{MCPCRU}_{DAM} - \mathrm{RUOPR}_{q,r,DAM}) * \mathrm{PCRUR}_{q,r,DAM})$$
$$+ ((\mathrm{MCPCRD}_{DAM} - \mathrm{RDOPR}_{q,r,DAM}) * \mathrm{PCRDR}_{q,r,DAM})$$
$$+ ((\mathrm{MCPCRR}_{DAM} - \mathrm{RROPR}_{q,r,DAM}) * \mathrm{PCRRR}_{q,r,DAM})$$
$$+ ((\mathrm{MCPCECR}_{DAM} - \mathrm{ECRSOPR}_{q,r,DAM}) * \mathrm{PCECRR}_{q,r,DAM})$$
$$+ ((\mathrm{MCPCNS}_{DAM} - \mathrm{NSOPR}_{q,r,DAM}) * \mathrm{PCNSR}_{q,r,DAM}))$$

Day-Ahead Point-to-Point Obligation Impact

$$\mathrm{DAMRTPTPQSEAMT}_{q} = (-1) * \sum_{j} \sum_{k} ((\mathrm{RTOBLPR}_{(j,k)} - \mathrm{DAOBLPR}_{(j,k)}) * \mathrm{RTOBL}_{q,(j,k)})$$

Where:

$$\mathrm{RTOBLPR}_{(j,k)} = \sum_{i=1}^{4} (\mathrm{RTSPP}_{(k,i)} - \mathrm{RTSPP}_{(j,i)}) / 4$$
$$\mathrm{DAOBLPR}_{(j,k)} = \mathrm{DASPP}_{k} - \mathrm{DASPP}_{j}$$

(f) If any RUC short charges occur for any Operating Hour involved in a Market Participant’s recovery under this Section, ERCOT will evaluate the Market Participant’s revised position to determine if the Market Participant is entitled to a refund, or should be charged for RUC short charge;

(g) Any resulting charge or payment to the Market Participant will be invoiced using a miscellaneous Invoice, but allocated with the method outlined in paragraphs (2) through (4) of Section 9.19.1, Default Uplift Invoices.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\mathrm{DAMSQSEAMT}_{q}$	$	*Day-Ahead Market Energy Sales Amount by QSE*—The sum of the DAM Energy Sales positions compared to Real-Time results, for the QSE *q*, for the 15-minute Settlement Interval.
$\mathrm{DAMPQSEAMT}_{q}$	$	*Day-Ahead Market Energy Purchases Amount by QSE*—The sum of the DAM Energy purchases compared to Real-Time results, for the QSE *q*, for the 15-minute Settlement Interval.
$\mathrm{DAMASQSEAMT}_{q}$	$	*Day-Ahead Market Ancillary Service Amount by QSE*—The sum of the DAM Ancillary Service awarded amounts compared to Real-Time results, for the QSE *q*, for the hour.
$\mathrm{DAMRTPTPQSEAMT}_{q}$	$	*Day-Ahead Market Real-Time Point-to-Point Obligation Amount by QSE*—The sum of the PTP Obligation bids cleared in the DAM compared to Real-Time results, for the QSE *q*, for the hour.
DASPP_{p}	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM Settlement Point Price at Settlement Point *p*, for the hour.

$\text{RTOBL}_{q, (j, k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids that would have cleared in the DAM and settled in Real-Time for the source *j,* and the sink *k*, for the hour.
RTSPP_{p}	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point for the 15-minute Settlement Interval within the hour.
$\text{DAES}_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s Three-Part Supply Offers that would have cleared in the DAM and DAM Energy-Only Offer Curves that would have cleared in the DAM at Settlement Point *p*, for the hour.
$\text{DAEP}_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s DAM Energy Bids that would have cleared at Settlement Point *p*, for the hour.
$\text{PCRUR}_{q, r, DAM}$	MW	*Procured Capacity for Regulation Up from Resource per QSE per Resource in DAM*—The Regulation Up Service (Reg-Up) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{PCRDR}_{q, r, DAM}$	MW	*Procured Capacity for Regulation Down from Resource per QSE per Resource in DAM*—The Regulation Down Service (Reg-Down) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{PCRRR}_{q, r, DAM}$	MW	*Procured Capacity for Responsive Reserve from Resource per QSE per Resource in DAM*—The Responsive Reserve (RRS) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{PCNSR}_{q, r, DAM}$	MW	*Procured Capacity for Non-Spinning Reserve from Resource per QSE per Resource in DAM*—The Non-Spinning Reserve (Non-Spin) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

[NPRR903: Insert the variable for "PCECRR $_{q, r, DAM}$" below upon system implementation of NPRR863:]

$\text{PCECRR}_{q, r, DAM}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service from Resource per QSE per Resource in DAM*—The ERCOT Contingency Reserve Service (ECRS) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

$\text{RUOPR}_{q, r, DAM}$	$/MW per hour	*Regulation Up Offer Price*—The offer price for Resource *r* represented by QSE *q,* for the impacted Reg-Up Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RDOPR}_{q, r, DAM}$	$/MW per hour	*Regulation Down Offer Price*—The offer price for Resource *r* represented by QSE *q,* for the impacted Reg-Down Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RROPR}_{q, r, DAM}$	$/MW per hour	*Responsive Reserve Offer Price*—The offer price for Resource *r* represented by QSE *q,* for the impacted RRS Ancillary Service Offers. Where for a Combined Cycle

		Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

[NPRR903: Insert the variable for "$ECRSOPR_{q, r, DAM}$" below upon system implementation of NPRR863:]

$ECRSOPR_{q, r, DAM}$	\$/MW per hour	*ERCOT Contingency Reserve Service Offer Price*—The offer price for Resource *r* represented by QSE *q,* for the impacted ECRS Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

$NSOPR_{q, r, DAM}$	\$/MW per hour	*Non-Spinning Reserve Offer Price*—The offer price for Resource *r* represented by QSE *q,* for the impacted Non-Spin Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$MCPCRU_{DAM}$	\$/MW per hour	*Market Clearing Price for Capacity for Regulation Up in DAM*—The DAM Market Clearing Price for Capacity (MCPC) for Reg-Up, for the hour.
$MCPCRD_{DAM}$	\$/MW per hour	*Market Clearing Price for Capacity for Regulation Down in DAM*—The DAM MCPC for Reg-Down, for the hour.
$MCPCRR_{DAM}$	\$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for RRS, for the hour.
$MCPCNS_{DAM}$	\$/MW per hour	*Market Clearing Price for Capacity for Non-Spinning Reserve in DAM*—The DAM MCPC for Non-Spin, for the hour.

[NPRR903: Insert the variable for "$MCPCECR_{DAM}$" below upon system implementation of NPRR863:]

$MCPCECR_{DAM}$	\$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service in DAM*—The DAM MCPC for ECRS, for the hour.

$DAOBLPR_{(j, k)}$	\$/MWh	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation bid with the source *j,* and the sink *k*, for the hour.
$RTOBLPR_{(j, k)}$	\$/MWh	*Real-Time Obligation Price per pair of source and sink*—The Real-Time calculated price of a PTP Obligation bid with the source *j,* and the sink *k*, for the 15 minute period.
q	none	A QSE.
r	none	A Resource.
i	none	A 15-minute Settlement Interval.
k	none	A sink Settlement Point.
p	none	A Settlement Point.
j	none	A source Settlement Point.

9.15 Settlement Charges

(1) The calculations to be used for Settlement charges are contained in Section 4, Day-Ahead Operations, Section 5, Transmission Security Analysis and Reliability Unit Commitment, Section 6, Adjustment Period and Real-Time Operations, Section 7, Congestion Revenue Rights, and Section 9, Settlement and Billing.

9.15.1 Charge Type Matrix

(1) ERCOT shall post a Charge Type Matrix on the ERCOT website that summarizes each Charge Type by variable name used in the Protocols, description, and Protocol section number reference. ERCOT post changes to this Charge Type Matrix at least ten days before implementation of change.

9.16 ERCOT System Administration and User Fees

9.16.1 ERCOT System Administration Fee

(1) The Public Utility Commission of Texas (PUCT) has authorized ERCOT to charge the ERCOT System Administration fee to fund ERCOT's budget. ERCOT converts the fee into a charge to each Qualified Scheduling Entity (QSE) using the formula set forth in paragraph (3) below.

(2) ERCOT shall post the ERCOT System Administration fee on the ERCOT website. Within two Business Days following PUCT approval of a change in the ERCOT System Administration fee, ERCOT shall post the changed fee and effective date on the ERCOT website.

(3) Each QSE shall pay the ERCOT System Administration fee. The ERCOT System Administration fee is for each 15-minute Settlement Interval for each QSE.

$$\textbf{ESACAMT}_{q} \quad = \quad \textbf{LAFF * max(0,} \sum_{p} \textbf{RTAML}_{q,\,p}\textbf{)}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
ESACAMT $_{q}$	$	*ERCOT System Administration Fee*—The ERCOT System Administration fee for each QSE per 15-minute Settlement Interval.
RTAML $_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load*— The sum of the Adjusted Metered Load (AML) at the Electrical Buses included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
LAFF	$/MWh	*Load Administration Fee Factor*—The ERCOT System Administration fee.
q	none	A QSE.
p	none	A Settlement Point. The summation is over all of the Settlement Points.

9.16.2 User Fees

(1) The ERCOT Board approves user fees for products and services provided by ERCOT to a Market Participant or other Entity. Such user fees are approved in accordance with the ERCOT Board Policies and Procedures. User fees may include, but are not limited to, application fees, private Wide Area Network (WAN) costs, interconnection study fees and map sale fees.

(2) ERCOT shall post user fees approved by the ERCOT Board in the ERCOT Fee Schedule on the ERCOT website. ERCOT shall post the ERCOT Fee Schedule and effective date on the ERCOT website within two Business Days of change.

(3) A Market Participant or other Entity shall pay applicable user fees approved by the ERCOT Board.

9.17 Transmission Billing Determinant Calculation

(1) ERCOT shall provide Market Participants with the key parameters and formula components required by a Transmission Service Provider (TSP) or Distribution Service Provider (DSP) in determining the billing charges for the use of its Transmission Facilities or Distribution Facilities ("Transmission Billing Determinants"). ERCOT is not responsible for billing, collection, or disbursal of payments associated with transmission access service.

9.17.1 Billing Determinant Data Elements

(1) ERCOT shall calculate and provide to Market Participants on the ERCOT website the following data elements annually to be used by TSPs and DSPs as billing determinants for transmission access service. This data must be provided by December 1 of each year. This calculation must be made under the requirements of P.U.C. SUBST. R. 25.192, Transmission Service Rates. ERCOT shall use the most recent aggregate data produced by the ERCOT Settlement system to perform these calculations.

(a) The 4-Coincident Peak (4-CP) for each DSP and External Load Serving Entity (ELSE), as applicable;

(b) The ERCOT average 4-CP;

(c) The average 4-CP for each DSP and ELSE, as applicable, coincident to the ERCOT average 4-CP.

(2) ERCOT average 4-CP is defined as the average of the coincidental MW peaks occurring during the months of June, July, August, and September.

(3) Coincidental MW peak is defined as the highest monthly Settlement Interval 15-minute MW peak for the entire ERCOT Transmission Grid as calculated per the following formula: The sum of all net energy produced by Generation Resources + Settlement Only Generators (SOGs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual Direct Current Tie (DC Tie) imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity's (NOIE's) Load - actual DC Tie exports - Wholesale Storage Load (WSL).

[NPRR995: Replace paragraph (3) above with the following upon system implementation:]

(3) Coincidental MW peak is defined as the highest monthly Settlement Interval 15-minute MW peak for the entire ERCOT Transmission Grid as calculated per the following formula: The sum of all net energy produced by Generation Resources + Settlement Only Generators (SOGs) + Settlement Only Energy Storage Systems (SOESSs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual Direct Current Tie (DC Tie) imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity's (NOIE's) Load - actual DC Tie exports - Wholesale Storage Load (WSL).

(4) Any difference between the coincidental MW peak (converted to MWh) and the ERCOT Settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, and WSL, shall be allocated amongst all DSPs and ELSEs that are included in the ERCOT 4-CP Report on a pro rata basis as per the formula below:

$$\mathbf{LTDSP\_4CP}_{\,tdsp} = (\mathbf{PLTDSP4CPLRS}_{\,tdsp} * \mathbf{NLADJ}) + \mathbf{PLTDSP4CP}_{\,tdsp}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LTDSP_4CP $_{tdsp}$	MWh	*Load by TDSP for 4-CP* - The load for each DSP and ELSE coincident to the coincidental MW peak adjusted for NLADJ
PLTDSP4CPLRS $_{tdsp}$	%	*Preliminary Load by TDSP for 4-CP Load Ratio Share* - The Load Ratio Share (LRS) for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
NLADJ	MWh	*Native Load Adjustment* - The difference between the coincidental MW peak (converted to MWh) and the ERCOT settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, and WSL
PLTDSP4CP $_{tdsp}$	MWh	*Preliminary Load by TDSP for 4CP* - The Load for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
tdsp	None	A DSP or ELSE

9.17.2 Direct Current Tie Schedule Information

(1) Within ten Business Days of receipt of a request by a TSP or DSP for data pertaining to transactions over the DC Ties for the immediately preceding month, ERCOT shall provide the following Electronic Tag (e-Tag) data:

(a) Tagging identifier (Tag Code);

(b) Date of transaction;

(c) Megawatt-hours (MWh) actually transferred;

(d) Sending Generation Control Area (GCA);

(e) Receiving Load Control Area (LCA);

(f) Purchasing / Scheduling Entity (PSE);

(g) Entity scheduling the export of power over a DC Tie; and

(h) Status of Transaction (Implement, Withdrawn, Cancelled, Conditional, etc.).

(2) ERCOT shall maintain and provide the requesting TSP or DSP data pertaining to transactions over the DC Ties for the period from June 2001 to the present. For each transaction, the same data as specified in paragraph (1) above, must be provided.

9.18 Profile Development Cost Recovery Fee for Non-ERCOT Sponsored Load Profile Segment

(1) Paragraph (e)(3) of P.U.C. SUBST. R. 25.131, Load Profiling and Load Research, requires that ERCOT establish and implement a process to collect a fee from any Retail Electric Provider (REP) who seeks to assign customers to a non-ERCOT sponsored profile segment. The process must include a method for other REPs who use the profile segment to compensate the original requestor of the new profile segment and for ERCOT to notify Distribution Service Providers (DSPs) which REPs are authorized to use the new profile segment. This profile development cost recovery fee is overseen by ERCOT.

(2) Within 30 days after a profile segment receives final approval from ERCOT, the requestor shall submit to ERCOT documentation of the costs it incurred in developing the profile segment change request. All such documentation must be available for review by any Market Participant. Any costs submitted more than 30 days after approval of the profile segment will not be recoverable. Recoverable costs must be directly attributable to the creation of the profile segment change request, incurred no earlier than 24 months preceding the original submission date of the profile segment change request, and must be further limited to:

(a) Costs for Load research as paid to DSPs or ERCOT, documented by a copy of all DSP or ERCOT Invoices or other evidence of payment, including but not limited to:

(i) Buying and installing Interval Data Recorders (IDRs);

(ii) Installing communication equipment such as phone lines or cell phones; and

(iii) Reading the meters and translating the data.

(b) Reasonable costs paid to third parties, including a copy of all third-party invoices or other documentary evidence of payment, including:

(i) Defining the request, such as identifying population, profile, data, etc.;

(ii) Preparing the request, such as collecting and analyzing data and presenting the case; and

(iii) Undertaking the review process such as meeting with ERCOT, Profiling Working Group (PWG), Retail Market Subcommittee (RMS), Technical Advisory Committee (TAC), and the ERCOT Board.

(c) Requestor's reasonable internal documented costs itemizing all persons, hours, and other expenses associated with developing the request per paragraphs (1) and (2) above.

(3) Within 60 days after ERCOT approves a profile segment, ERCOT shall evaluate the costs submitted and shall disallow any costs not meeting these criteria. The remaining costs must comprise the total reimbursable cost. Within the same 60-day period, ERCOT shall post a report on the ERCOT website summarizing the allowed expenses by paragraphs (1) and (2) above. If a Market Participant, including the requestor, disagrees with the ERCOT determination with respect to the total reimbursable cost, the Market Participant may submit a dispute as outlined in Section 20, Alternative Dispute Resolution Procedure. No disputes may be submitted after 45 days from posting of the total reimbursable cost to the ERCOT website.

(4) The fee is calculated as follows:

If a REP is the requestor, then: $FEE = \$C / n$

If the requestor is not a REP, then:

$FEE = \$C / (n + 1)$

The above variables are defined as follows:

Variable	Definition
n	The number of REPs subscribing to the profile segment
$C	The total reimbursable cost

(5) The fee must be paid by each successive subscribing REP to the requestor and any previous subscribing REPs per instructions and validation by ERCOT. As additional REPs subscribe to the profile segment, the fee is recalculated and reallocated equally among all subscribing REPs and the requestor, if the requestor is not a REP.

(6) Beginning four years after the date on which the profile segment becomes available for Settlement, any REP may request assignment of Electric Service Identifiers (ESI IDs) to the profile segment without being assessed the profile development cost recovery fee.

9.19 Partial Payments by Invoice Recipients

(1) If at least one Invoice Recipient owing funds does not pay its Settlement Invoice in full (short-pay), ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient prior to four hours preceding the close of the Bank Business Day Central Prevailing Time (CPT) on the day that payments by ERCOT are due to be paid to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available Financial Security pledged to ERCOT by each short-paying Invoice Recipient that did not pay the amount due under paragraph (a) above. If the amount of any such draw is greater than the amount of the short-paying Invoice Recipient's cash collateral held in excess of that required to cover its Total Potential Exposure (TPE) ("Excess Collateral"), then a draw on available security for a short-paying Invoice Recipient shall be considered a Late Payment for purposes of Section 16.11.6, Payment Breach and Late Payments by Market Participants. ERCOT may, in its sole discretion, hold up to 5% of Financial Security of each short-paying Invoice Recipient and use those funds to pay subsequent Settlement Invoices as they become due. Any funds still held will be applied to unpaid Invoices in conjunction with the default uplift process outlined in Section 9.19.1, Default Uplift Invoices.

(c) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT to a short-paying Invoice Recipient against amounts not paid by that Invoice Recipient, and ERCOT shall apply the amount offset or recouped to cover short pays by that Invoice Recipient. ERCOT may, in its sole discretion, hold credit Invoices and use those funds to pay subsequent Settlement Invoices as they become due. Any funds still held will be offset or recouped against unpaid Invoices in conjunction with the default uplift process outlined in Section 9.19.1.

(d) If, after taking the actions set forth in paragraphs (a), (b) and (c) above, ERCOT still does not have sufficient funds to pay all amounts that it owes to Settlement Invoice Recipients in full, ERCOT shall deduct any applicable administrative fees as specified in Section 9.16, ERCOT System Administration and User Fees, payments for Reliability Must-Run (RMR) Services, and the Congestion Revenue Right (CRR) Balancing Account (CRRBA) from the amount received or collected and then reduce payments to all Settlement Invoice Recipients owed monies from ERCOT. The reductions must be based on a pro rata basis of monies owed to each Settlement Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short pays and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the Settlement Invoice.

(e) If sufficient funds continue to be unavailable for ERCOT to pay all amounts in full to short-paid Entities for that Settlement Invoice and the short-paying Entity is not complying with a payment plan designed to enable ERCOT to pay all amounts in full to short-paid Entities, ERCOT shall uplift short-paid amounts through the Default Uplift process described below in Section 9.19.1 and Section 9.19.2, Payment Process for Default Uplift Invoices.

(f) When ERCOT enters into a payment plan with a short-pay Invoice Recipient, ERCOT shall post to the Market Information System (MIS) Secure Area:

(i) The short-pay plan;

(ii) The schedule of quantifiable expected payments, updated if and when modifications are made to the payment schedule; and

(iii) Invoice dates to which the payments will be applied.

(g) To the extent ERCOT is able to collect past due funds owed by a short-paying Invoice Recipient before the default uplift process defined in Section 9.19.1, ERCOT shall allocate the collected funds to the earliest short-paid Invoice for that short-paying Invoice Recipient. ERCOT shall use its best efforts to distribute collected funds quarterly by the 15th Business Day following the end of a calendar quarter for a short paying Entity when the cumulative amount of undistributed funds held exceed $50,000 on a pro rata basis of monies owed. Subsequently collected funds that have not previously been distributed will be applied against unpaid Invoices in conjunction with the uplift process outlined in Section 9.19.1.

(h) To the extent ERCOT is able to collect past due funds owed by a short-paying Invoice Recipient, after the default uplift process defined in Section 9.19.1, ERCOT shall allocate the collected funds using the same allocation method as in the default uplift process. ERCOT shall use its best efforts to distribute subsequently collected funds quarterly by the 15th Business Day following the end of a calendar quarter for a short paying Entity when the cumulative amount of undistributed funds held exceed $50,000.

9.19.1 Default Uplift Invoices

(1) ERCOT shall collect the total short-pay amount for all Settlement Invoices for a month, less the total payments expected from a payment plan, from Qualified Scheduling Entities (QSEs) and CRR Account Holders. ERCOT must pay the funds it collects from payments on Default Uplift Invoices to the Entities previously short-paid. ERCOT shall notify those Entities of the details of the payment.

(2) Each Counter-Party's share of the uplift is calculated using the best available Settlement data for each Operating Day in the month prior to the month in which the default occurred (the "reference month"), and is calculated as follows:

$$\mathbf{DURSCP}_{cp} = \mathbf{TSPA} * \mathbf{MMARS}_{cp}$$

Where:

$$\text{MMARS}_{cp} = \text{MMA}_{cp} / \text{MMATOT}$$

$$\begin{aligned}\text{MMA}_{cp} = \text{Max}\ \{ & \textstyle\sum_{mp} (\text{URTMG}_{mp} + \text{URTDCIMP}_{mp} + \text{USOGTOT}_{mp}),\\ & \textstyle\sum_{mp} (\text{URTAML}_{mp} + \text{UWSLTOT}_{mp}),\\ & \textstyle\sum_{mp} \text{URTQQES}_{mp},\\ & \textstyle\sum_{mp} \text{URTQQEP}_{mp},\\ & \textstyle\sum_{mp} \text{UDAES}_{mp},\\ & \textstyle\sum_{mp} \text{UDAEP}_{mp},\\ & \textstyle\sum_{mp} (\text{URTOBL}_{mp} + \text{URTOBLLO}_{mp}),\\ & \textstyle\sum_{mp} (\text{UDAOPT}_{mp} + \text{UDAOBL}_{mp} + \text{UOPTS}_{mp} + \text{UOBLS}_{mp}),\\ & \textstyle\sum_{mp} (\text{UOPTP}_{mp} + \text{UOBLP}_{mp})\}\end{aligned}$$

[NPRR995 and NPRR1012: Replace applicable portions of the formula "MMA $_{cp}$" above with the following upon system implementation for NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]

$$\begin{aligned}\text{MMA}_{cp} = \text{Max}\ \{ & \textstyle\sum_{mp} (\text{URTMG}_{mp} + \text{URTDCIMP}_{mp} + \text{USOGTOT}_{mp}),\\ & \textstyle\sum_{mp} (\text{URTAML}_{mp} + \text{UWSLTOT}_{mp} + \text{USOCLTOT}_{mp}),\\ & \textstyle\sum_{mp} \text{URTQQES}_{mp},\\ & \textstyle\sum_{mp} \text{URTQQEP}_{mp},\\ & \textstyle\sum_{mp} \text{UDAES}_{mp},\\ & \textstyle\sum_{mp} \text{UDAEP}_{mp},\\ & \textstyle\sum_{mp} (\text{URTOBL}_{mp} + \text{URTOBLLO}_{mp}),\\ & \textstyle\sum_{mp} (\text{UDAOPT}_{mp} + \text{UDAOBL}_{mp} + \text{UOPTS}_{mp} + \text{UOBLS}_{mp}),\\ & \textstyle\sum_{mp} (\text{UOPTP}_{mp} + \text{UOBLP}_{mp}),\\ & \textstyle\sum_{mp} \text{UDAASOAWD}_{mp}\}\end{aligned}$$

$$\text{MMATOT} = \sum_{cp} (\text{MMA}_{cp})$$

Where:

$\text{URTMG}_{mp} = \sum_{p,\, r,\, i} (\text{RTMG}_{mp,\, p,\, r,\, i})$, excluding RTMG for RMR Resources and RTMG in Reliability Unit Commitment (RUC)-Committed Intervals for RUC-committed Resources

$$\text{URTDCIMP}_{mp} = \sum_{p,\, i} (\text{RTDCIMP}_{mp,\, p,\, i}) / 4$$

$$\text{URTAML}_{mp} = \max(0, \sum_{p,\, i} (\text{RTAML}_{mp,\, p,\, i}))$$

$$\text{URTQQES}_{mp} = \sum_{p,\, i} (\text{RTQQES}_{mp,\, p,\, i}) / 4$$

$$\text{URTQQEP}_{mp} = \sum_{p,\, i} (\text{RTQQEP}_{mp,\, p,\, i}) / 4$$

$$\text{UDAES}_{mp} = \sum_{p,\, h} (\text{DAES}_{mp,\, p,\, h})$$

$$\text{UDAEP}_{mp} = \sum_{p,\, h} (\text{DAEP}_{mp,\, p,\, h})$$

$$\text{URTOBL}_{mp} = \sum_{(j,\, k),\, h} (\text{RTOBL}_{mp,\, (j,\, k),\, h})$$

$$\text{URTOBLLO}_{mp} = \sum_{(j,\, k),\, h} (\text{RTOBLLO}_{mp,\, (j,\, k),\, h})$$

$$\text{UDAOPT}_{mp} = \sum_{(j,\, k),\, h} (\text{DAOPT}_{mp,\, (j,\, k),\, h})$$

$$\text{UDAOBL}_{mp} = \sum_{(j,\, k),\, h} (\text{DAOBL}_{mp,\, (j,\, k),\, h})$$

$$\text{UOPTS}_{mp} = \sum_{(j,\, k),\, h} (\text{OPTS}_{mp,\, (j,\, k),\, h})$$

$$\text{UOBLS}_{mp} = \sum_{(j,\, k),\, h} (\text{OBLS}_{mp,\, (j,\, k),\, h})$$

$$\text{UOPTP}_{mp} = \sum_{(j,\, k),\, h} (\text{OPTP}_{mp,\, j,\, h})$$

$$\text{UOBLP}_{mp} = \sum_{(j,\, k),\, h} (\text{OBLP}_{mp,\, (j,\, k),\, h})$$

$$\text{UWSLTOT}_{mp} = (-1) * \sum_{r,\, b} (\text{MEBL}_{mp,\, r,\, b})$$

[NPRR1012: Insert the formula "UDAASOAWD $_{mp}$" below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

$$\text{UDAASOAWD}_{mp} = \sum_{h} (\text{DARUOAWD}_{mp,\, h} + \text{DARDOAWD}_{mp,\, h} + \text{DARROAWD}_{mp,\, h} + \text{DANSOAWD}_{mp,\, h} + \text{DAECROAWD}_{mp,\, h})$$

$$\text{USOGTOT}_{mp} = \sum_{gsc} (\text{MEBSOGNET}_{mp,\, gsc}) + \sum_{p,\, i} (\text{RTMGSOGZ}_{mp,\, p,\, i})$$

[NPRR995: Insert the formula "USOCLTOT $_{mp}$" below upon system implementation:]

$$USOCLTOT_{mp} = (-1) * \sum_{gsc,\, b} (WSOL_{mp,\, gsc,\, b})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DURSCP $_{cp}$	$	*Default Uplift Ratio Share per Counter-Party*—The Counter-Party's pro rata portion of the total short-pay amount for all Day-Ahead Market (DAM) and Real-Time Market (RTM) Invoices for a month.
TSPA	$	*Total Short Pay Amount*—The total short-pay amount calculated by ERCOT to be collected through the Default Uplift Invoice process.
MMARS $_{cp}$	None	*Maximum MWh Activity Ratio Share*—The Counter-Party's pro rata share of Maximum MWh Activity in the reference month.
MMA $_{cp}$	MWh	*Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction in the reference month.
MMATOT	MWh	*Maximum MWh Activity Total*—The sum of all Counter-Party's Maximum MWh Activity in the reference month.
RTMG $_{mp,\, p,\, r,\, i}$	MWh	*Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTMG $_{mp}$	MWh	*Uplift Real-Time Metered Generation per Market Participant*—The monthly sum of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTDCIMP $_{mp,\, p,\, i}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTDCIMP $_{mp}$	MW	*Uplift Real-Time DC Import per Market Participant*—The monthly sum of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party.
RTAML $_{mp,\, p,\, i}$	MWh	*Real-Time Adjusted Metered Load per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML) at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTAML $_{mp}$	MWh	*Uplift Real-Time Adjusted Metered Load per Market Participant*—The monthly sum of the AML represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQES $_{mp,\, p,\, i}$	MW	*QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTQQES $_{mp}$	MWh	*Uplift QSE-to-QSE Energy Sale per Market Participant*—The monthly sum of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.

Variable	Unit	Definition
RTQQEP $_{mp, p, i}$	MW	*QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTQQEP $_{mp}$	MWh	*Uplift QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAES $_{mp, p, h}$	MW	*Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE.
UDAES $_{mp}$	MWh	*Uplift Day-Ahead Energy Sale per Market Participant*—The monthly total of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAEP $_{mp, p, h}$	MW	*Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared DAM Energy Bids at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.
UDAEP $_{mp}$	MWh	*Uplift Day-Ahead Energy Purchase per Market Participant*—The monthly total of energy represented by Market Participant *mp*'s cleared DAM Energy Bids, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBL $_{mp, (j, k), h}$	MW	*Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE.
URTOBL $_{mp}$	MWh	*Uplift Real-Time Obligation per Market Participant*—The monthly total of Market Participant *mp*'s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBLLO $_{q, (j, k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
URTOBLLO $_{q, (j, k)}$	MW	*Uplift Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The monthly total of Market Participant *mp*'s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAOPT $_{mp, (j, k), h}$	MW	*Day-Ahead Option per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
UDAOPT $_{mp}$	MWh	*Uplift Day-Ahead Option per Market Participant*—The monthly total of Market Participant *mp*'s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.

Variable	**Unit**	**Definition**
DAOBL $_{mp,\ (j,\ k),\ h}$	MW	*Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
UDAOBL $_{mp}$	MWh	*Uplift Day-Ahead Obligation per Market Participant*—The monthly total of Market Participant *mp*'s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTS $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOPTS $_{mp}$	MWh	*Uplift PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLS $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOBLS $_{mp}$	MWh	*Uplift PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTP $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOPTP $_{mp}$	MWh	*Uplift PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLP $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOBLP $_{mp}$	MWh	*Uplift PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
UWSLTOT $_{mp}$	MWh	*Uplift Metered Energy for Wholesale Storage Load at bus per Market Participant*—The monthly sum of Market Participant *mp*'s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL.
MEBL $_{mp,\ r,\ b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*.

Variable	Unit	Definition
[NPRR1012: Insert the variables below upon system implementation of the Real-Time Co-Optimization (RTC) project:]		
UDAASOAWD_{mp}	MWh	*Uplift Day-Ahead Ancillary Service Only Award per Market Participant*—The monthly total of Market Participant *mp's* Ancillary Service Only Offers awarded in DAM, where the Market Participant is a QSE assigned to the registered Counter-Party.
$\text{DARUOAWD}_{mp,\ h}$	MW	*Day-Ahead Reg-Up Only Award per Market Participant*—The Reg-Up Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
$\text{DARDOAWD}_{mp,\ h}$	MW	*Day-Ahead Reg-Down Only Award per Market Participant*—The Reg-Down Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
$\text{DARROAWD}_{mp,\ h}$	MW	*Day-Ahead Responsive Reserve Only Award per Market Participant*—The Responsive Reserve (RRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
$\text{DANSOAWD}_{mp,\ h}$	MW	*Day-Ahead Non-Spin Only Award per Market Participant*—The Non-Spin Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
$\text{DAECROAWD}_{mp,\ h}$	MW	*Day-Ahead ERCOT Contingency Reserve Service Only Award per Market Participant*—The ERCOT Contingency Reserve Service (ECRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
USOGTOT_{mp}	MWh	*Uplift Real-Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by Settlement Only Generators (SOGs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. ***[NPRR995: Replace the definition above with the following upon system implementation:]*** *Uplift Real-Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by Settlement Only Generators (SOGs), Settlement Only Distribution Generators (SODGs), Settlement Only Transmission Generators (SOTGs), Settlement Only Distribution Energy Storage Systems (SODESSs), or Settlement Only Transmission Energy Storage Systems (SOTESSs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
[NPRRR995: Insert the variable "USOCLTOT $_{mp}$" below upon system implementation:]		
USOCLTOT_{mp}	MWh	*Uplift Real-Time Settlement Only Charging Load per Market Participant*—The monthly sum of Real-Time charging Load that is WSL by SODESSs and SOTESSs represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.

Variable	Unit	Definition
RTMGSOGZ $_{mp.\ p,\ i}$	MWh	*Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Energy Storage System (ESS), Settlement Only Distribution Generators (SODGs), and Settlement Only Transmission Generators (SOTGs) at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that opted out of nodal pricing pursuant to Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG), will also be included in this value. ***[NPRR995: Replace the definition above with the following upon system implementation:]*** *Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Energy Storage System (ESS), SODGs, and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that opted out of nodal pricing pursuant to Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS), will also be included in this value.
MEBSOGNET $_{q,\ gsc}$	MWh	*Net Metered energy at gsc for an SODG or SOTG Site*—The net sum for all Settlement Meters for SODG or SOTG site *gsc* represented by QSE *q*. A positive value indicates an injection of power to the ERCOT System. ***[NPRR995: Replace the definition above with the following upon system implementation:]*** *Net Metered energy at gsc for an SODG, SOTG, SODESS, or SOTESS Site*—The net sum for all Settlement Meters for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by QSE *q* for the 15-minute Settlement Interval. A positive value indicates an injection of power to the ERCOT System.
[NPRRR995: Insert the variable "WSOL $_{mp,\ gsc,\ b}$" below upon system implementation:]		
WSOL $_{mp,\ gsc,\ b}$	MWh	*WSL for an SODESS or SOTESS Site*—The WSL as measured for an for SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by the Market Participant *mp,* represented as a negative value, for the 15-minute Settlement Interval.
cp	none	A registered Counter-Party.
mp	none	A Market Participant with MWh activity in the reference month that is a currently-registered QSE or CRR Account Holder or that voluntarily terminated its QSE or CRR Account Holder registration.

Variable	**Unit**	**Definition**
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.
gsc	none	A generation site code.
b	none	An Electrical Bus.

(3) The uplifted short-paid amount will be allocated to the Market Participants (QSEs or CRR Account Holders) assigned to a registered Counter-Party based on the pro-rata share of MWhs that the QSE or CRR Account Holder contributed to its Counter-Party's maximum MWh activity ratio share.

(4) Any uplifted short-paid amount greater than $2,500,000 must be scheduled so that no amount greater than $2,500,000 is charged on each set of Default Uplift Invoices until ERCOT uplifts the total short-paid amount. ERCOT must issue Default Uplift Invoices at least 30 days apart from each other.

(5) ERCOT shall issue Default Uplift Invoices no earlier than 90 days following a short-pay of a Settlement Invoice on the date specified in the Settlement Calendar. The Invoice Recipient is responsible for accessing the Invoice on the MIS Certified Area once posted by ERCOT.

(6) Each Default Uplift Invoice must contain:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due or Payable – the aggregate summary of all charges owed by a Default Uplift Invoice Recipient;

(d) Run Date – the date on which ERCOT created and published the Default Uplift Invoice;

(e) Invoice Reference Number – a unique number generated by the ERCOT applications for payment tracking purposes;

(f) Default Uplift Invoice Reference – an identification code used to reference the amount uplifted;

(g) Payment Date and Time – the date and time that Default Uplift Invoice amounts must be paid;

(h) Remittance Information Details – details including the account number, bank name, and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due; and

(i) Overdue Terms – the terms that would apply if the Market Participant makes a late payment.

(7) Each Invoice Recipient shall pay any net debit shown on the Default Uplift Invoice on the payment due date whether or not there is any Settlement and billing dispute regarding the amount of the debit.

9.19.2 Payment Process for Default Uplift Invoices

(1) Payments for Default Uplift Invoices are due on a Bank Business Day and Business Day basis in a two-day, two-step process as detailed in this Section 9.19.2.

9.19.2.1 Invoice Recipient Payment to ERCOT for Default Uplift

(1) The payment due date and time for the Default Uplift Invoice with funds owed by an Invoice Recipient is 1700 on the fifth Bank Business Day after the Default Uplift Invoice date, unless fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All Default Uplift Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars (USDs) by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal) on or before the payment due date.

9.19.2.2 ERCOT Payment to Invoice Recipients for Default Uplift

(1) Subject to the availability of funds as discussed in paragraph (2) below, uplifted funds received from Default Uplift Invoices must be paid by ERCOT to short-paid Invoice Recipients by 1700 on the next Bank Business Day after payments are due for that Default Uplift Invoice under Section 9.19.2.1, Invoice Recipient Payment to ERCOT for Default Uplift, subject to ERCOT's right to withhold payments under Section 16, Registration and Qualification of Market Participants, or pursuant to common law unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit to each short-paid Invoice Recipient for same day value the amounts determined by ERCOT to be available for payment to that short-paid Invoice Recipient under paragraph (1)(d) of Section 9.19, Partial Payments by Invoice Recipients.

(3) Any short payments of Default Uplift Invoices must be handled under Section 9.19, Partial Payments by Invoice Recipients.

9.19.3 Default Uplift Supporting Data Reporting

(1) ERCOT shall post once each month on the MIS Certified Area, the Maximum MWh Activity (MMA), Maximum MWh Activity Total (MMATOT), Maximum MWh Activity Ratio Share (MMARS), and the Counter-Party level components of MMA calculation as defined in paragraph (2) of Section 9.19.1, Default Uplift Invoices. Each month's report shall be updated with Final and True-Up Settlement data when ERCOT's systems contain the necessary information to complete the report with the updated data.

9.19.4 Exemption for Central Counter-Party Clearinghouses Regulated as Derivatives Clearing Organizations

(1) Notwithstanding any other provision of Section 9.19, Partial Payments by Invoice Recipients, or these Protocols, ERCOT shall not issue a Default Uplift Invoice to, and shall not otherwise collect any short-pay amounts from, any QSE that:

- (a) Otherwise would be subject to an uplift charge solely as a result of acting as a central Counter-Party clearinghouse in wholesale market transactions in ERCOT; and
- (b) Is regulated as a Derivatives Clearing Organization as defined by the Commodity Exchange Act, 7 U.S.C. § 1a.

ERCOT Nodal Protocols

Section 10: Metering

January 1, 2023

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10 METERING

10.1 Overview

(1) This Section specifies the responsibilities and requirements for meter data, certification of Metering Facilities, meter standards, approved meter types and the process for auditing, testing, and maintenance of Metering Facilities to be used in the ERCOT Region.

(2) Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) are the only Entities authorized to provide Settlement Meter data to ERCOT. ERCOT shall maintain a Meter Data Acquisition System (MDAS) to collect generation and consumption energy data for Settlement purposes under these Protocols. The MDAS must receive Customer Load meter data from TSPs and DSPs and must collect data from all ERCOT-Polled Settlement (EPS) Meters.

(3) All Service Delivery Points, excluding EPS, Settlement Only Distribution Generator (SODG), or Non-Opt-In Entity (NOIE) metering points, that meet the requirements of P.U.C. SUBST. R. 25.311, Competitive Metering Services, are eligible for competitive meter ownership pursuant to such Public Utility Commission of Texas (PUCT) Substantive Rule. All competitively owned meters shall meet all the applicable metering requirements of these Protocols and the Retail Market Guide Section 10, Competitive Metering.

[NPRR995: Replace paragraph (3) above with the following upon system implementation:]

(3) All Service Delivery Points, excluding EPS, Settlement Only Distribution Generator (SODG), Settlement Only Distribution Energy Storage System (SODESS), or Non-Opt-In Entity (NOIE) metering points, that meet the requirements of P.U.C. SUBST. R. 25.311, Competitive Metering Services, are eligible for competitive meter ownership pursuant to such Public Utility Commission of Texas (PUCT) Substantive Rule. All competitively owned meters shall meet all the applicable metering requirements of these Protocols and the Retail Market Guide Section 10, Competitive Metering.

10.2 Scope of Metering Responsibilities

10.2.1 QSE Real-Time Metering

(1) The Qualified Scheduling Entity's (QSE's) responsibility for Real-Time metering requirements is contained in Section 6.5.5.2, Operational Data Requirements.

10.2.2 TSP and DSP Metered Entities

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) is responsible for supplying ERCOT with meter data associated with:

(a) All Loads using the ERCOT System;

(b) Any Settlement Only Distribution Generator (SODG); a DSP may make some or all such meters ERCOT-Polled Settlement (EPS) compliant and may request that ERCOT poll the meters. Notwithstanding the foregoing sentence, meter data is not required from:

(i) Generation owned by a Non-Opt-In Entity (NOIE) and used for the NOIE's self-use (not serving Customer Load);

(ii) Distributed Renewable Generation (DRG) with a design capacity less than 50 kW interconnected to a DSP where the owner chooses not to have the out-flow measured in accordance with P.U.C. SUBST. R. 25.213, Metering for Distributed Renewable Generation; and

(iii) Distributed Generation (DG) interconnected to a DSP behind a registered NOIE boundary metering point, not registered as a Generation Resource and with an installed capacity below the DG registration threshold, as determined in Section 16.5, Registration of a Resource Entity, and posted on the ERCOT website.

(c) NOIE or External Load Serving Entity (ELSE) points of delivery where metering points are radial Loads and are uni-directionally metered and NOIE points of delivery that have bi-directional flows that are solely the result of generation interconnected to a Transmission and/or Distribution Service Provider (TDSP) owned Distribution System behind a NOIE point of delivery metering point. A TSP or DSP has the option of making some or all such meters EPS compliant and to request that ERCOT poll the meters; and

(d) Generation participating in a current Emergency Response Service (ERS) Contract Period, where such generation only exports energy to the ERCOT System during an ERS deployment or ERS test.

(2) Each TSP and DSP is responsible for the following:

(a) Compliance with the procedures and standards in this Section, the Settlement Metering Operating Guide (SMOG) and the Operating Guides;

(b) Installation, control, and maintenance of the Settlement Metering Facilities, as more fully described in this Section and the SMOG, which includes meters, recorders, instrument transformers, wiring, and miscellaneous equipment required to measure electrical energy;

(c) Costs incurred in the installation and maintenance of these Metering Facilities and communications except for incremental costs incurred for functions not required for the Settlement of the Load or Generation Resource, Settlement Only Generator (SOG), or Load Resource. These incremental costs shall be borne by the Entities requesting the service pursuant to the TSP or DSP tariffs; and

(d) Installation, maintenance, data collection, and related communications, telemetry for the Metering Facilities, and related services necessary to meet the mandatory Interval Data Recorder (IDR) requirements detailed in this Section, Section 18, Load Profiling, and the SMOG.

10.2.3 ERCOT-Polled Settlement Meters

(1) ERCOT shall poll Metering Facilities that meet any one of the following criteria:

(a) Generation connected directly to the ERCOT Transmission Grid, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT Transmission Grid during equipment testing, an ERS deployment, or an ERS test;

(b) Auxiliary meters used for generation netting by ERCOT;

(c) Generation delivering 10 MW or more to the ERCOT System, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT System during equipment testing, an ERS deployment, or an ERS test;

(d) Generation participating in any Ancillary Service market;

(e) NOIE points connected bi-directionally to the ERCOT System, unless the bi-directional energy flows are the sole result of generation interconnected to a TDSP owned Distribution System behind a NOIE point of delivery metering point;

(f) Direct Current Ties (DC Ties);

(g) DG where there is an energy storage Load Resource that has associated Wholesale Storage Load (WSL);

[NPRR995: Replace paragraph (g) above with the following upon system implementation:]

(g) Metering required to determine the Wholesale Storage Load (WSL) or Non-WSL Settlement Only Charging Load associated to a Settlement Only Distribution Energy Storage System (SODESS) or Settlement Only Transmission Energy Storage System (SOTESS);

(h) Metering required to determine WSL associated with an Energy Storage Resource (ESR); and

(i) Metering required to determine the Non-WSL ESR Charging Load.

(2) Additionally, ERCOT shall poll any SODG or NOIE metering point at the request of such Entity, provided the Metering Facility meets all requirements and approvals associated with EPS metering requirements of this Section and the SMOG. Load Resources of 10 MW or more on the ERCOT System, may, at their option have an EPS Meter.

10.2.3.1 Entity EPS Responsibilities

(1) The following defines the responsibilities of Entities regarding EPS metering:

(a) EPS Meters must be polled directly by ERCOT, which shall then convert the raw data to Settlement Quality Meter Data in accordance with this Section, Section 11, Data Acquisition and Aggregation, and the SMOG.

(b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP "EPS Meter Inspector," which is defined as an employee or agent of the TSP or DSP who has received EPS training from ERCOT, and is described further herein. This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter ESR auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values.

[NPRR995: Replace paragraph (b) above with the following upon system implementation:]

(b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP "EPS Meter Inspector," which is defined as an employee or agent of the TSP or DSP who has received EPS training from ERCOT, and is described further herein. This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter ESR, SODESS, or SOTESS auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values.

(c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG, except for Resource Entity-owned equipment used to measure, calculate, or telemeter an auxiliary Load value for an ESR pursuant to Section 10.2.4.

[NPRR995: Replace paragraph (c) above with the following upon system implementation:]

(c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG, except for Resource Entity-owned equipment used to measure, calculate, or telemeter an auxiliary Load value for an ESR, SODESS, or SOTESS pursuant to Section 10.2.4.

(d) Each TSP and DSP shall install and maintain a Back-up Meter(s) at each EPS Meter location for Resources, auxiliary netting, and bi-directional meter points. A "Back-up Meter" is defined as a redundant revenue quality EPS Meter connected at the same metering point as the primary EPS Meter and meeting the requirements defined in the SMOG.

(e) Costs incurred in the installation and maintenance of EPS metered Facilities and communications will be the responsibility of the TSP or DSP except for incremental costs incurred for functions not required for the energy settlement as required by these Protocols. These incremental costs shall be borne by the Entities requesting the service, as per the TSP's or DSP's tariffs.

(f) Specific operating practices for EPS Metering Facilities are included in the SMOG.

10.2.4 Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values

(1) When the Resource Entity certifies, the interconnecting TDSP confirms by approving the metering design, and, based on the information provided by the TDSP as part of the EPS Design Proposal, ERCOT agrees that metering of an ESR's WSL separate from the ESR's auxiliary Load is not feasible based on the ESR's physical design, the Resource Entity for that ESR shall be permitted to calculate the auxiliary Load using measurements from its own internal sensors and telemeter a Real-Time aggregated value for that Load to the TDSP's EPS Meter. The Resource Entity may telemeter a zero Load value only when the ESR is discharging more than the calculated auxiliary Load. The methodology by which the auxiliary Load is calculated is subject to ERCOT approval.

(2) An officer of the Resource Entity shall annually attest to the methodology and validity of the auxiliary Load calculation, as further described in the SMOG. The Resource Entity shall include with its annual attestation the findings of an independent audit performed by a registered Texas Professional Engineer confirming the auxiliary Load calculation does not understate the Load value. The audit shall be based on laboratory testing that reflects the anticipated field conditions of the same model of sensor as that used by the Resource Entity or validation using measurements by other devices over the past year, as further described in the SMOG. The audit shall evaluate the impact of any degradation in accuracy of the sensors over time.

(3) If the Resource Entity is unable to provide the attestation and audit findings meeting the requirements of paragraph (2) above, it shall either reconfigure the Resource Entity's site and resubmit its meter design within 30 days to allow for separately metering the WSL, or forfeit WSL treatment.

(4) ERCOT may conduct an audit of the Resource Entity's processes, equipment, and calculation of the auxiliary Load.

(5) The TSP or DSP shall assign all costs required for separately metering the auxiliary Load for WSL treatment to the EPS Meter to the Resource Entity.

[NPRR995: Replace Section 10.2.4 above with the following upon system implementation:]

10.2.4 Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values

(1) When the Resource Entity certifies, the interconnecting TDSP confirms by approving the metering design, and, based on the information provided by the TDSP as part of the EPS Design Proposal, ERCOT agrees that metering of an ESR's WSL separate from the ESR's, SODESS's, or SOTESS's auxiliary Load is not feasible based on the ESR's, SODESS's, or SOTESS's physical design, the Resource Entity for that ESR, SODESS, or SOTESS shall be permitted to calculate the auxiliary Load using measurements from its own internal sensors and telemeter a Real-Time aggregated value for that Load to the TDSP's EPS Meter. The Resource Entity may telemeter a zero Load value only when the ESR, SODESS, or SOTESS is discharging more than the calculated auxiliary Load. The methodology by which the auxiliary Load is calculated is subject to ERCOT approval.

(2) An officer of the Resource Entity shall annually attest to the methodology and validity of the auxiliary Load calculation, as further described in the SMOG. The Resource Entity shall include with its annual attestation the findings of an independent audit performed by a registered Texas Professional Engineer confirming the auxiliary Load calculation does not understate the Load value. The audit shall be based on laboratory testing that reflects the anticipated field conditions of the same model of sensor as that used by the Resource Entity or validation using measurements by other devices over the past year, as further described in the SMOG. The audit shall evaluate the impact of any degradation in accuracy of the sensors over time.

(3) If the Resource Entity is unable to provide the attestation and audit findings meeting the requirements of paragraph (2) above, it shall either reconfigure the Resource Entity's site and resubmit its meter design within 30 days to allow for separately metering the WSL or forfeit WSL treatment.

(4) ERCOT may conduct an audit of the Resource Entity's processes, equipment, and calculation of the auxiliary Load.

(5) The TSP or DSP shall assign all costs required for separately metering the auxiliary Load for WSL treatment to the EPS Meter to the Resource Entity.

10.2.4.1 Responsibilities for Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values

(1) For each site at which a Resource Entity telemeters its auxiliary Load value, as permitted by Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values:

(a) The Resource Entity shall:

(i) Provide supporting information on the equipment, configuration, drawings and processes used to calculate the telemetry signal, including supporting information on the calculation of the telemetry signal for inclusion in the EPS Design Proposal.

(ii) Provide documentation of the auxiliary Load calculation methodology as defined in this Section and the SMOG.

(iii) Install, control, and maintain the sensors, instrumentation, wiring, communications, and other equipment required to calculate and provide the telemetry signal.

(iv) Provide and update contact information for a person designated for communication regarding the auxiliary Load supporting information and data.

(v) Act in accordance with any TDSP requirements concerning EPS Meters and Metering Facilities in the Protocols and SMOG that pertain to the following issues:

(A) Calculation of Load values and data estimation issues;

(B) The provision of notice to ERCOT regarding any outage or any other issue affecting the accuracy of the Load calculation or the availability of the telemetry of the Load value; and

(C) The implementation of any proposed change to the calculation or equipment, as documented in the EPS Design Proposal; and

(vi) Provide any information requested by ERCOT or the TDSP with respect to the measurement, calculation, and/or telemetry of the auxiliary Load value.

(b) The interconnecting TDSP shall:

(i) Use an EPS Meter to calculate 15-minute energy values from the Resource Real-Time telemetry signal for the auxiliary Load and store the data in the EPS Meter for retrieval by the ERCOT Meter Data Acquisition System (MDAS); and

(ii) Include an auxiliary Load metering point on the EPS Design Proposal that represents the calculation of the telemetry signal.

(c) ERCOT shall:

(i) Review the Resource-provided data on the calculation of the telemetry signal submitted as part of the EPS Design Proposal to ensure compliance with defined rules in this Section and the SMOG; and

(ii) Request assistance and information from the Resource-designated contact for items related to the telemetry.

[NPRR995: Replace Section 10.2.4.1 above with the following upon system implementation:]

10.2.4.1 Responsibilities for Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values

(1) For each site at which a Resource Entity telemeters its auxiliary Load value, as permitted by Section 10.2.4, Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values:

(a) The Resource Entity shall:

(i) Provide supporting information on the equipment, configuration, drawings and processes used to calculate the telemetry signal, including supporting information on the calculation of the telemetry signal for inclusion in the EPS Design Proposal.

(ii) Provide documentation of the auxiliary Load calculation methodology as defined in this Section and the SMOG.

(iii) Install, control, and maintain the sensors, instrumentation, wiring, communications, and other equipment required to calculate and provide the telemetry signal.

(iv) Provide and update contact information for a person designated for communication regarding the auxiliary Load supporting information and data.

(v) Act in accordance with any TDSP requirements concerning EPS Meters and Metering Facilities in the Protocols and SMOG that pertain to the following issues:

(A) Calculation of Load values and data estimation issues;

(B) The provision of notice to ERCOT regarding any outage or any other issue affecting the accuracy of the Load calculation or the availability of the telemetry of the Load value; and

(C) The implementation of any proposed change to the calculation or equipment, as documented in the EPS Design Proposal; and

(vi) Provide any information requested by ERCOT or the TDSP with respect to the measurement, calculation, and/or telemetry of the auxiliary Load value.

(b) The interconnecting TDSP shall:

(i) Use an EPS Meter to calculate 15 minute energy values from the Resource Real-Time telemetry signal for the auxiliary Load and store the data in the EPS Meter for retrieval by the ERCOT Meter Data Acquisition System (MDAS); and

(ii) Include an auxiliary Load metering point on the EPS Design Proposal that represents the calculation of the telemetry signal.

(c) ERCOT shall:

(i) Review the Resource-provided data on the calculation of the telemetry signal submitted as part of the EPS Design Proposal to ensure compliance with defined rules in this Section and the SMOG; and

(ii) Request assistance and information from the Resource-designated contact for items related to the telemetry.

10.3 Meter Data Acquisition System (MDAS)

10.3.1 Purpose

(1) The Meter Data Acquisition System (MDAS) will be used:

(a) By ERCOT to obtain and receive Revenue Quality Meter data from the ERCOT-Polled Settlement (EPS) Meters and Settlement Quality Meter Data from the Transmission Service Provider (TSP) and Distribution Service Provider (DSP) for Settlement and billing purposes; and,

(b) To populate the ERCOT Data Archive used by Market Participants or their agents with authority to access Settlement Quality Meter Data held by ERCOT.

10.3.2 ERCOT-Polled Settlement Meters

(1) Each TSP and DSP shall, in accordance with these Protocols and the Settlement Metering Operating Guide (SMOG), provide ERCOT-approved metering communication equipment and connection to permit ERCOT access to the TSP's or DSP's EPS Meters.

(2) ERCOT shall retrieve meter data electronically and automatically by MDAS. ERCOT may also collect meter data on demand.

10.3.2.1 Generation Resource Meter Splitting

(1) Each Generation Resource meter must be represented by only one Qualified Scheduling Entity (QSE), except that a jointly owned Generation Resource unit or group of Generation Resources may split the net generation output into two or more Split Generation Resources for a Resource Entity. Each Resource Entity representing a Split Generation Resource may have its energy and capacity scheduled through a separate QSE. For purposes of this paragraph, a jointly owned Generation Resource unit or group of Generation Resources shall also include the San Miguel and Gibbons Creek power projects and Intermittent Renewable Resources (IRRs) such as wind and solar generation.

(2) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the Resource Entities representing the Split Generation Resources shall be required to submit a percentage allocation of the Generation Resource to be used to determine the capacity available at each Split Generation Resource.

(3) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the owners of the Generation Resource shall submit all required ERCOT Facility registration documentation and an ERCOT-approved splitting agreement executed by an Authorized Representative from each owning Resource Entity. Such agreement shall contain a defined and fixed ownership percentage as among the owning Resource Entities. ERCOT shall establish this Generation Resource as a "split," essentially establishing Split Generation Resource meters. Generation splitting based on a static ratio is not permitted. Generation splitting requires Real-Time splitting signals.

10.3.2.1.1 Split Generation Resource Metering Real-Time Signal

(1) When a Split Generation Resource is registered with ERCOT, the QSE representing the Split Generation Resource shall provide ERCOT with a Real-Time signal of the MW of generation for the Split Generation Resource. The Real-Time MW signals must be revised every scan cycle and must represent the QSE's Split Generation Resource in positive MW.

(2) ERCOT shall integrate the Real-Time MW signals and provide a MWh value for each 15-minute interval for each Split Generation Resource.

(3) The settlement system shall use the integrated MWh per interval value to calculate the percentage breakdowns to be applied to the actual metered MWh values retrieved from the EPS Metering Facility.

10.3.2.1.2 Allocating EPS Metered Data to Split Generation Resource Meters

(1) ERCOT shall poll the EPS Metering Facilities related to the actual Generation Resource and store the meter data at 15-minute intervals. This metering data must be validated, edited, estimated, and compensated for losses, as necessary, and be netted as required. This resulting data must then have the Split Generation Resource ratios applied to assign the generation to the QSE representing each owner of the Split Generation Resources. The MWh quantities of the Split Generation Resources must be used in all Settlement calculations and reports.

(2) The following example illustrates the splitting of the generation data:

Splitting Example 1

Integrated values from ERCOT systems						**Actual Metered MWh**	**Data to be Used in Settlement**		
Interval Ending	**RID1 (MWh)**	**RID2 (MWh)**	**RID3 (MWh)**	**Total MWh**	**% Ratios Rid 1,2,3**		**Split MWh**	**Split MWh**	**Split MWh**
13:15	10	20	10	40	25, 50, 25	52	13	26	13

10.3.2.1.3 Processing for Missing Dynamic Split Generation Resource Signal

(1) For any interval when ERCOT has not received a Real-Time signal for any one of the Split Generation Resources, ERCOT shall use the last valid percentage ratio for a completed interval.

Splitting Example 2

Integrated values from ERCOT systems						**Actual Metered MWh**	**Data to be Used in Settlement**		
Interval Ending	**RID1 (MWh)**	**RID2 (MWh)**	**RID3 (MWh)**	**Total MWh**	**% Ratios Rid 1,2,3**		**Split MWh**	**Split MWh**	**Split MWh**
13:15	10	20	10	40	25, 50, 25	52	13	26	13
13:30	NA	21	10	NA	Ratio Above	55	13.75	27.5	13.75
13:45	NA	22	10	NA	Ratio Above	48	12	24	12

10.3.2.1.4 Calculating the Split Generation Resource Ratio

(1) For Split Generation Resources, ERCOT shall provide for Settlement the net MWh value for each 15-minute interval. This value is the MWh accumulated based on the MW value over each scan cycle. ERCOT shall use a standard "integration" mechanism to perform this function.

(2) For Settlement, ERCOT shall use the integrated data to determine the allocation ratio as the integrated share of each signal divided by the integrated total of signals.

10.3.2.1.5 Split Generation Resource Data Made Available to Market Participants

(1) Market Participants shall have access to allocated generation output and ratio data only for Split Generation Resources that they represent.

10.3.2.1.6 Allocating EPS Metered Data to Generator Owners When It Is Net Load

(1) EPS Generation Resource sites that are netted by ERCOT may have multiple Competitive Retailers (CRs) associated with the Load. ERCOT shall poll the EPS metering facilities related to the actual Generation Resource facility and store the meter data at 15-minute intervals. ERCOT shall perform validation, editing, estimation, compensation for losses as necessary, and netting as required for EPS metering data. For intervals when data is net Load, the fixed ownership percentages stored in the asset database must be used to allocate the consumption to multiple Electric Service Identifiers (ESI IDs). The consumption quantities for the ESI IDs must be used in all energy settlement calculations and reports.

10.3.2.2 Loss Compensation of EPS Meter Data

(1) Where the EPS Meter is not located at the Point of Interconnection (POI) to the ERCOT Transmission Grid, actual metered consumption must be adjusted for line and transformation losses to the POI in accordance with Settlement Metering Operating Guide (SMOG) Section 8, Transformer and Line Loss Compensation Factors. The preferred method for loss compensation and correction is via internal meter programming.

(2) Recognizing the fact that some locations may not have the total functionality necessary to perform internal compensation, the Data Aggregation System (DAS) must have the functionality to perform approved loss compensation as necessary. ERCOT shall retain the discretion to allow or deny the continued use of this type of metering.

(3) No meter may be compensated internally for losses more than once. ERCOT may compensate multiple meters prior to netting to the POI. Pulse communications transfer of data between meters is not allowed.

10.3.2.3 Generation Netting for ERCOT-Polled Settlement Meters

(1) Each Generation Resource and Settlement Only Generator (SOG) and each Load that is designated to be netted with that Generation Resource or SOG, including construction and maintenance Load that is netted with existing generation auxiliaries, must be physically metered at its POI to the ERCOT Transmission Grid or Service Delivery Point, or, in accordance with Section 10.3.2.2, Loss Compensation of EPS Meter Data,

loss-compensated to its POI to the ERCOT Transmission Grid. Interval Data Recorders (IDRs) must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load, and carry any applicable Load shared charges and credits.

(2) For Settlement purposes, netting is not allowed except under the configurations described in paragraphs (2)(a) through (2)(e) below, and only if the service arrangement is otherwise lawful. ERCOT has no obligation to independently determine whether a site configuration that includes both Loads and Generation Resource(s) or SOGs complies with Public Utility Regulatory Act (PURA) or the Public Utility Commission of Texas (PUCT) Substantive Rules, and ERCOT's approval of a metering proposal for such a site is not a verification of the legality of that arrangement:

(a) Single POI or Service Delivery Point;

(b) Transmission-level interconnections where all POIs are located at the same substation, at the same voltage, and under normal operating conditions, are interconnected through common electrical equipment such as circuit breakers, connecting cables, bus bars, switches/isolators. Qualifying station arrangements include, but are not limited to, Generation and Load connected in a line bus, ring bus, double-breaker, or breaker-and-a-half configuration;

(c) Multiple POIs where the Loads and generator output are electrically connected to a common switchyard, as defined in paragraph (6) below. In addition, there must be sufficient generator capacity to serve all plant Loads for netting to occur;

(d) A Qualifying Facility (QF) with POIs, where the QF is selling energy to a thermal host, may net the Load meters of the thermal host with the QF's generation meters when the Load and generation are electrically connected to a common switchyard. In instances in which Load is served by new on-site generation through a common switchyard, the TSP or DSP may install monitoring equipment necessary for measuring Load to determine stranded cost charges, if any are applicable, as determined under the PURA and applicable PUCT rules. For purposes of this Section, new on-site generation has the meaning as contained in Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 39.252 and 39.262(k) (Vernon 1998 & Supp. 2007) (PURA); or

(e) For Generation Resources and/or Load with flow-through on a private, contiguous transmission system (not included in a TSP or DSP rate base) and in a configuration existing as of October 1, 2000, the meters at the interconnections with the ERCOT Transmission Grid may be netted for the purpose of determining Generation Resources or Load. For Settlement purposes, when the net is a Load, the metered interconnection points must be assigned to the same Load Zone and Unaccounted for Energy (UFE) zone.

(3) For Energy Storage Resource (ESR) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.

(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 (6) 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 (6) below.

(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.

(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.

(6) 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.

(7) 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 Transmission and/or Distribution Service Provider (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 (8) below upon system implementation:]

(8) 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.

10.3.2.4 Reporting of Net Generation Capacity

(1) Each Resource Entity with either a Generation Resource or Settlement Only Transmission Self-Generator (SOTSG) in a Private Use Network shall complete and submit the declaration in Section 22, Attachment L, Declaration of Private Use Network

Net Generation Capacity Availability, to ERCOT by February 1 of each year, stating its projected annual changes in net generation capacity available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and annual changes as of May 31 for the next ten subsequent years. ERCOT will use the aggregated capacity forecasts for the Report on Capacity, Demand and Reserves in the ERCOT Region, pursuant to Section 3.2.6.2.2, Total Capacity Estimate.

10.3.3 TSP or DSP Metered Entities

10.3.3.1 Data Responsibilities

(1) Each TSP and DSP shall be responsible for the following:

(a) Providing consumption data for each ESI ID and RID on at least a monthly basis according to the data timeliness and accuracy standards defined in this Section and in the SMOG;

(b) Providing start date, stop date, ESI ID or RID, and consumption data in kWh as well as an identifier for "estimated" reads as applicable;

(c) Submitting a single Demand value for each non-IDR ESI ID that has a Demand register to ERCOT if, and only if, a Demand value is required for TSP or DSP tariffs or for CR Customer billing. If the CR and TSP or DSP do not require a Demand value, then the TSP or DSP shall not submit a Demand value to ERCOT even if the meter has a Demand register;

(d) Validation, Editing, and Estimation of meter data (VEE) according to the standards in this Section before submitting data to the settlement process;

(e) Calculating consumption for any unmetered services by ESI ID and submitting such data monthly to ERCOT, subject to ERCOT audit. These calculations must be made pursuant to TSP and DSP-approved tariffs; and

(f) Metering all Loads, unless the Load meets one of the following criteria:

(i) Energy consumption by substation Facilities and equipment for the purpose of transporting electricity (e.g., substation transformers, fans, etc.).

(ii) Unmetered energy consumption represented by an ERCOT-approved Load Profile; or

(iii) Energy charge and discharge and associated losses for the ERCOT Board-approved storage devices installed as part of a transmission reliability project for the Presidio substation Facilities.

10.3.3.2 Retail Load Meter Splitting

(1) Retail Service Delivery Points with Loads above 1 MW may split their actual meter data into a maximum of four consumption values with each value being assigned a unique ESI ID; provided, however, that if a Customer is using Provider of Last Resort (POLR) or the "Price-to-Beat" retail service, such Customer may not split its meter signal among multiple CRs through this Section.

10.3.3.2.1 Retail Customer Load Splitting Mechanism

(1) Customer meter data may be split into separate ESI IDs by the installation of a programmable signal splitter that would take the master meter signal and split it into no more than four separate values that must at all times equal the total output of the master meter signal. Splitting of Customer meter data must meet the following requirements:

(a) The signal splitter may be programmed to split the Load in any way the Customer chooses, provided that such splitting results in positive Load;

(b) The Customer, or its CR(s), shall provide the signal splitter and shall be responsible for all costs of installing, maintaining, and operating the signal splitter, any associated equipment, and communications;

(c) The TSP or DSP shall be responsible for approving the specifications and installation of any signal splitting devices;

(d) IDRs shall be required on the master Customer Load meter and each of the split channels for verification and settlement purposes;

(e) The TSP or DSP metering system recording such split signals (four ESI IDs) may be required to be redundant if so provided by TSP or DSP tariffs;

(f) The split signals must be recorded in Real-Time and cannot be altered or substituted later in time;

(g) One Entity shall be designated to pay the total TSP and/or DSP charges for the Customer; and

(h) Switching of CRs for the individual split-metered Customers shall comply with the registration procedures in Section 19, Texas Standard Electronic Transaction.

10.3.3.2.2 TSP and DSP Responsibilities Associated with Retail Customer Load Splitting

(1) Each consumption value from a Customer Load split meter shall be assigned a separate ESI ID by the TSP or DSP. Each ESI ID may be assigned to a separate CR. The master meter may not be assigned an ESI ID.

(2) The TSP or DSP shall send interval data for each ESI ID for the ERCOT settlement system.

(3) The TSP or DSP shall be responsible for verifying that the sum of the split ESI ID IDR data equals the total IDR value from the master meter.

10.3.3.2.3 ERCOT Requirements for Retail Load Splitting

(1) ERCOT shall settle all ESI IDs in the same manner.

(2) ERCOT shall not receive or process the IDR data associated with the master meter.

10.3.3.3 Submission of Settlement Quality Meter Data to ERCOT

(1) Settlement Quality Meter Data shall be submitted to ERCOT on a periodic cycle, but no later than monthly:

  (a) For provisioned Advanced Meters and Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ IDRs, Settlement Quality Meter Data will be submitted using an ERCOT specified file format for the interval data only, which will be used for Settlement.

    (i) The monthly non-interval total consumption and demand (if applicable) values for these ESI IDs shall be provided to ERCOT and Load Serving Entities (LSEs) using the appropriate Texas Standard Electronic Transactions (TX SETs) in order to effectuate the registration transactions outlined in Section 15, Customer Registration.

    (ii) These non-interval total consumption and demand values will not be used for Settlement.

  (b) For all other meters, Settlement Quality Meter Data will be submitted using the appropriate TX SET.

(2) Each TSP or DSP shall ensure that consumption meter data submitted to ERCOT is in intervals of:

  (a) 15-minutes for those ESI IDs and RIDs served by IDRs; and

  (b) Monthly or on an ERCOT-approved meter reading cycle for non-IDRs.

(3) The Settlement Quality Meter Data submitted by TSP or DSP must be in kWh and kVArh values (as applicable).

10.3.3.3.1 Past Due Data Submission

(1) ERCOT shall provide a report to the appropriate TSP and DSP for any ESI ID or RID for which consumption data has not been received in the past 38 days. Upon receipt of the missing consumption data report, the TSP or DSP shall have two Business Days to submit the missing consumption data.

10.4 Certification of EPS Metering Facilities

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) shall certify ERCOT-Polled Settlement (EPS) Metering Facilities in a manner approved by ERCOT.

10.4.1 Overview

(1) This Section describes the steps that a TSP or DSP shall use to certify each EPS Metering Facility and the steps ERCOT shall use to approve each EPS Metering Facility. This Section also describes the manner in which EPS Metering Facility approval requests must be made to ERCOT.

10.4.2 EPS Design Proposal Documentation Required from the TSP or DSP

(1) Before installation of new EPS Meters, TSP or DSP shall provide ERCOT with an EPS Design Proposal of the Metering Facilities being considered for ERCOT approval as EPS Meter Facilities. An "EPS Design Proposal" is the documentation required on the form available on the ERCOT website. Included one line drawings must be dated, detailed, bear the current drawing revision number, and show all devices which contribute to the burden in the metering circuits. Other information may also be required by ERCOT for review regarding the meter and related installation and Facilities; such additional information shall be promptly provided to ERCOT by the TSP or DSP upon request of ERCOT.

10.4.2.1 Approval or Rejection of an EPS Design Proposal for EPS Metering Facilities

(1) ERCOT may unconditionally approve, conditionally approve, or reject an EPS Design Proposal.

10.4.2.1.1 Unconditional Approval

(1) If ERCOT unconditionally approves an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been approved. The TSP or DSP may then commence installation of the EPS Metering Facilities in accordance with the EPS Design Proposal.

10.4.2.1.2 Conditional Approval

(1) Notification of Conditional Approval:

If ERCOT conditionally approves an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been conditionally approved. It shall set forth in such Notice the conditions on which approval is granted and the time period in which each such condition must be satisfied by the TSP or DSP.

(2) Ability to Satisfy Conditions:

If the TSP or DSP disputes any condition imposed by ERCOT, the TSP or DSP must promptly notify ERCOT of its concerns and provide ERCOT with the reasons for its concerns. If the TSP or DSP provides ERCOT such Notice, ERCOT may amend or withdraw any of the conditions on which it granted its approval or ERCOT may require the TSP or DSP to satisfy other conditions. ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on accomplishing the installation.

(3) Notification of Satisfaction of Conditions:

The TSP or DSP shall promptly notify ERCOT when each condition in the approval has been satisfied and provide to ERCOT any information reasonably requested by ERCOT as evidence that such condition has been satisfied.

(4) Confirmation of Satisfaction of Conditions:

If ERCOT determines that a condition has been satisfied, then ERCOT shall provide the TSP or DSP written confirmation that the condition has been satisfied.

(5) Unsatisfied Conditions:

If ERCOT determines that a condition has not been satisfied, ERCOT shall notify the TSP or DSP that it does not consider the condition satisfied and shall set out in such Notice the reason(s) that it does not consider the condition satisfied. If, after using good faith efforts, ERCOT and the TSP or DSP are unable to agree on whether the condition is satisfied, either Entity may refer the dispute to the Alternative Dispute Resolution (ADR) Procedures as described in Section 20, Alternative Dispute Resolution Procedure.

10.4.2.1.3 Rejection

(1) If ERCOT rejects an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been rejected and shall set forth the reasons for its rejection. The TSP or DSP shall submit to ERCOT a revised EPS Design Proposal after receiving such Notice. If ERCOT rejects for a second time an EPS Design Proposal submitted by a TSP or DSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on the requirements and disputed items. In the absence of agreement either

Entity may refer the dispute to the ADR Procedures as described in Section 20, Alternative Dispute Resolution Procedure.

10.4.3 Site Certification Documentation Required from the TSP or DSP EPS Meter Inspector

(1) A TSP or DSP EPS Meter Inspector shall complete an ERCOT site certification form for each set of EPS Metering Facilities that it inspects. The site certification form is the official form used to document whether EPS Metering Facilities meet ERCOT criteria.

(2) The TSP or DSP EPS Meter Inspector shall promptly notify ERCOT and document any discrepancy between ERCOT approved EPS Design Proposal on file and the actual Metering Facilities inspected by the TSP or DSP EPS Meter Inspector.

(3) The TSP or DSP shall provide the documents as outlined in Settlement Metering Operating Guide (SMOG) for each set of EPS Metering Facilities being considered for ERCOT approval.

10.4.3.1 Review by ERCOT

(1) ERCOT shall review the ERCOT site certification documentation prepared by the TSP or DSP EPS Meter Inspector within 45 days of receipt. If ERCOT finds that this data is incomplete or demonstrates that the EPS Metering Facilities fail to meet the standards contained within this Section or the SMOG, ERCOT shall promptly provide written or electronic notice of the deficiencies to the TSP or DSP.

(2) ERCOT shall notify the TSP or DSP of the approval of the Metering Facility. ERCOT shall return a copy of the schematic drawings, and a copy of the ERCOT site certification form marked by ERCOT as approved. ERCOT shall retain a copy of these documents.

10.4.3.2 Provisional Approval

(1) If ERCOT finds that the documentation: provided by the TSP or DSP is incomplete or demonstrates that the EPS Metering Facility fails to meet the standards contained within this Section and SMOG; then ERCOT may, elect to issue a provisional approval for the Metering Facility. The terms and conditions on which such provisional approval is issued shall be at ERCOT’s discretion and shall be defined for the TSP or DSP. ERCOT shall not issue an approval until such time as all of the conditions of the provisional approval have been fulfilled to the satisfaction of ERCOT. ERCOT shall post any provisional approvals on the ERCOT website on a quarterly basis.

10.4.3.3 Obligation to Maintain Approval

(1) Once an EPS Metering Facility has been installed, it is the responsibility of the TSP or DSP to ensure that the EPS Metering Facility complies with the approval criteria referred to in this Section and the SMOG.

10.4.3.4 Revocation of Approval

(1) ERCOT may revoke in full or in part any approval of Metering Facilities, including a provisional approval if:

(a) ERCOT or a TSP or DSP EPS Meter Inspector demonstrates that all or part of the EPS Metering Facilities covered by that approval no longer meet the approval criteria for EPS Metering Facilities contained in this Section and the SMOG; and

(b) ERCOT has given written Notice to the TSP or DSP stating that the identified EPS Metering Facilities do not meet the approval criteria and the reasons and that the TSP or DSP fails to correct the deficiency and satisfy ERCOT, within 30 days, that the EPS Metering Facilities meet the approval criteria.

(2) If ERCOT revokes in full or part an approval of EPS Metering Facilities, the TSP or DSP may seek re-approval of the EPS Metering Facilities by requesting approval in accordance with this Section.

10.4.3.5 Changes to Approved EPS Metering Facilities

(1) Each TSP and DSP shall notify ERCOT of any planned modifications or changes to be made to any EPS Metering Facilities that would affect the EPS Metering Facility’s approval, not less than ten Business Days prior to the intended implementation of the change. Before the intended date of the change, ERCOT may request additional information from the TSP or DSP to demonstrate that the EPS Metering Facilities will still meet the applicable approval standards; the TSP or DSP shall promptly comply with such request for information. ERCOT may at its discretion audit Metering Facilities to determine compliance. The TSP or DSP shall provide ERCOT with meter specific program details, as downloaded from the meter, when the EPS Meter is programmed.

10.4.3.6 Confirmation of Certification

(1) On the written request of ERCOT, the TSP or DSP shall provide ERCOT written or electronic confirmation that the Metering Facilities of each metered Entity that the TSP or DSP represents have been certified in accordance with this Section and the SMOG within five Business Days of receiving such a request from ERCOT.

10.5 TSP and DSP EPS Meter Inspectors

10.5.1 List of TSP and DSP EPS Meter Inspectors

(1) ERCOT shall maintain a list of TSP and DSP ERCOT-Polled Settlement (EPS) Meter Inspectors, and details related to ERCOT training to become a Transmission Service Provider (TSP) or Distribution Service Provider (DSP) EPS Meter Inspector.

10.5.2 EPS Meter Inspector Approval Process

10.5.2.1 TSP and DSP Responsibilities

(1) Each TSP and DSP shall ensure that personnel performing EPS Meter Facility certification duties are approved EPS Meter Inspectors and comply with this Section and the Settlement Metering Operating Guide (SMOG). A TSP or DSP EPS Meter Inspector is required to complete an ERCOT EPS Meter Inspector training session.

(2) The TSP and DSP shall submit to ERCOT the following information for individuals performing EPS Metering Facility certification.

(a) Name of individual;

(b) Time period the individual has been testing Generation Resource or transmission interconnect metering points;

(c) TSP or DSP statement indicating that the individual has the technical expertise to perform EPS Metering Facility certification; and,

(d) Additional documentation as required by ERCOT.

10.5.2.2 ERCOT Responsibilities

(1) ERCOT shall hold EPS Meter Inspector training sessions on a regularly scheduled basis. Sessions must include information on the following:

(a) Market responsibilities of EPS Meter Inspectors;

(b) Documentation requirements for the site certification;

(c) Overview of EPS Metering Facilities related topics and documents;

(d) Protocols requirements;

(e) SMOG requirements; and

(f) Technical requirements.

(2) ERCOT shall issue a certificate of attendance to individuals upon completion of the EPS Meter Inspector training sessions.

(3) ERCOT shall have the authority to revoke an individual's involvement with EPS Metering Facility certification.

10.6 Auditing and Testing of Metering Facilities

10.6.1 EPS Meter Entities

10.6.1.1 ERCOT Requirement for Audits and Tests

(1) ERCOT shall have the right to audit any ERCOT-Polled Settlement (EPS) Metering Facility that it considers necessary or to request and witness a test carried out by a Transmission Service Provider (TSP) or Distribution Service Provider (DSP) EPS Meter Inspector.

10.6.1.2 TSP and DSP Testing Requirements for EPS Metering Facilities

(1) At a minimum, the TSP and DSP EPS Meter Inspector shall conduct testing of EPS Meters on an annual basis, within the same month of each year as the previous year's test. Metering Facilities used in the ERCOT system for settlement must be tested pursuant to the TSP or DSP tariffs, the Settlement Metering Operating Guide and these Protocols.

(2) Instrument transformers used in settlement metering circuits must be tested per the American National Standards Institute (ANSI) C12.1, Code for Electricity Metering, and the following guidelines:

(a) Magnetic Instrument Transformers do not require periodic testing;

(b) Coupling Capacitor Voltage Transformers (CCVTs) shall be tested for accuracy:

(i) By the end of the year in which the fifth anniversary of the previous test occurs; or

(ii) By the end of the year in which the sixth anniversary of the previous test occurs, if the previous test occurred during the fourth quarter of the year.

(3) ERCOT may determine that periodic testing of CCVTs is not required once these devices have been proven to be stable. If the devices have shown themselves to be unstable, ERCOT may discontinue the use of these devices for settlement purposes.

10.6.1.3 Failure to Comply

(1) If an EPS Metering Facility fails to comply with ERCOT's audit or test procedures, ERCOT shall issue a warning to the TSP or DSP responsible for such Metering Facilities. If the TSP or DSP fails to comply with ERCOT's recommendations in a reasonable time, as determined by ERCOT, ERCOT shall notify the Public Utility Commission of Texas (PUCT) or the appropriate Governmental Authority.

10.6.1.4 Requests by Market Participants

(1) Market Participants shall follow appropriate Governmental Authority rules for requesting the testing of Metering Facilities.

10.6.2 TSP and DSP Metered Entities

10.6.2.1 Requirement for Audit and Testing

(1) Audit and Testing by a TSP or DSP

Each TSP or DSP shall conduct (or engage a qualified Entity to conduct) audits and tests of the Metering Facilities of the TSP or DSP Metered Entities that it represents to ensure compliance with all applicable requirements of any relevant Governmental Authority. Each TSP and DSP shall undertake any other actions that are reasonably necessary to ensure the accuracy and integrity of the meter data.

(2) Audit and Testing Requests by an affected Market Participant

Subject to any applicable Governmental Authority requirements, an affected Market Participant shall have the right to witness an audit or test carried out by the TSP or DSP or its authorized representative.

10.6.2.2 TSP and DSP Requirement to Certify per Governmental Authorities

(1) If a Governmental Authority has authority to certify meter installations, then the TSP or DSP shall comply with such regulations.

10.7 ERCOT Request for Installation of EPS Metering Facilities

10.7.1 Additional EPS Metering Installations

(1) If ERCOT determines that there is a potential need to install additional ERCOT-Polled Settlement (EPS) Metering Facilities on the ERCOT System, ERCOT shall notify the

relevant Transmission Service Provider (TSP) or Distribution Service Provider (DSP) in writing or electronically. ERCOT's Notice must include the following information:

(a) The location of the meter point at which the additional EPS Metering Facilities are required;

(b) The projected installation date by which the relevant EPS Metering Facilities should be installed;

(c) The reason for the need to install the additional EPS Metering Facilities; and

(d) Any other information that ERCOT considers relevant.

(2) A TSP or DSP that is notified by ERCOT of the potential need to install additional EPS Metering Facilities must:

(a) Give ERCOT written confirmation of receipt of Notice within three Business Days of receiving such Notice;

(b) Submit an EPS Design Proposal to ERCOT within 45 Business Days of receiving such Notice.

(3) The TSP or DSP may request a waiver to install additional Metering Facilities.

10.7.2 Approval or Rejection of Waiver Request for Installation of EPS Metering Facilities

(1) ERCOT may approve, or reject a waiver request at ERCOT's sole discretion.

10.7.2.1 Approval

(1) If ERCOT approves a waiver request, then ERCOT shall promptly notify the TSP or DSP.

10.7.2.2 Rejection

(1) If ERCOT rejects a waiver request, then ERCOT shall promptly notify the TSP or DSP and shall set forth the reasons for its rejection. The TSP or DSP may submit to ERCOT a revised waiver request within 14 Business Days of receiving such Notice. If ERCOT rejects for a second time a waiver request submitted by a TSP or DSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on the requirements and disputed items. In the absence of agreement either Entity may refer the dispute to the ADR Procedures as described in Section 20, Alternative Dispute Resolution Procedure.

10.8 Maintenance of Metering Facilities

10.8.1 EPS Meters

10.8.1.1 Duty to Maintain EPS Metering Facilities

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) shall maintain its ERCOT-Polled Settlement (EPS) Metering Facilities to meet the standards prescribed by this Section and the Settlement Metering Operating Guide (SMOG). If the EPS Metering Facilities of a TSP or DSP require maintenance to ensure that they operate in accordance with the requirements of this Section, SMOG, or any Governmental Authority, then the TSP or DSP shall notify ERCOT of the need for such maintenance. The TSP or DSP shall also inform ERCOT five Business Days in advance of the time period during which such maintenance is expected to occur. During that period, the TSP or DSP, or its authorized representative, after notifying ERCOT, shall be entitled to access sealed EPS Metering Facilities to which access is required in order to undertake the required maintenance.

10.8.1.2 EPS Metering Facilities Repairs

(1) If an EPS Metering Facility requires repairs to ensure that it operates in accordance with the requirements of this Section, then the TSP or DSP shall immediately notify ERCOT of the need for repairing such Metering Facility. If, however, operating conditions are such that it is not possible for the Transmission and/or Distribution Service Provider (TDSP) to notify ERCOT of the need for repairs, then the TDSP may make the necessary repairs and then notify ERCOT of the repairs prior to the end of the next Business Day.

(a) Where no Back-up Meter exists or Back-up Meter data is unavailable, the TSP or DSP shall ensure that the metering point is repaired and operational within 12 hours of problem detection. ERCOT may, at its discretion, reduce the repair timeline from 12 to six hours if the meter data is required for Real-Time Market (RTM) Settlements on the same day or an upcoming ERCOT non-Business Day.

(b) Where a functional and operational Back-up Meter exists, the TSP or DSP shall ensure that the metering point is repaired and operational within five Business Days of problem detection.

10.8.2 TSP or DSP Metered Entities

(1) Each TSP and DSP shall maintain its Metering Facilities in accordance with the requirements of the relevant Governmental Authorities and according to this Section.

10.9 Standards for Metering Facilities

(1) For Transmission Service Provider (TSP) and Distribution Service Provider (DSP) Metered Entities, an Interval Data Recorder (IDR) Meter is required on any of the following locations/sites:

(a) Non-Opt-In Entity (NOIE) or External Load Serving Entity (ELSE) metering points used to determine the total Load for that NOIE or ELSE; and

(b) Block Load Transfer (BLT) metering points, registered for Settlements in accordance with Section 6.5.9.5.1, Registration and Posting of BLT Points.

(2) For TSP and DSP Metered Entities, an IDR is required on any of the following locations/sites:

(a) Load Resources participating in the Ancillary Services markets, with the exception of Aggregate Load Resources (ALRs) for which statistical sampling is used to validate telemetry, as detailed in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets";

(b) Settlement Only Distribution Generators (SODGs); and

(c) Locations meeting IDR requirements defined in Section 18, Load Profiling.

10.9.1 ERCOT-Polled Settlement Meters

(1) The TSP or DSP for ERCOT-Polled Settlement (EPS) Meters shall ensure that the EPS Metering Facilities comply with this Section and the Settlement Metering Operating Guide (SMOG). This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter Energy Storage Resource (ESR) auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values.

[NPRR995: Replace paragraph (1) above with the following upon system implementation:]

(1) The TSP or DSP for ERCOT-Polled Settlement (EPS) Meters shall ensure that the EPS Metering Facilities comply with this Section and the Settlement Metering Operating Guide (SMOG). This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter Energy Storage Resource (ESR), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS) auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values.

(2) IDRs used for settlement of EPS Metering Facilities shall:

(a) Capture energy consumption and/or production in increments consistent with ERCOT defined Settlement Interval;

(b) Be able to capture energy in increments of five minutes (excluding memory allocation) for new and replacement IDRs used for settlement;

(c) Provide interval data for daily polling on a schedule that supports ERCOT's requirements (typically a daily cycle);

(d) Be capable of having data retrieved via telemetry by Meter Data Acquisition System (MDAS);

(e) Have battery or other energy-storage back-up to maintain time during power outages;

(f) Have remote time synchronization capability compatible with the MDAS;

(g) Maintain meter clocks on a time reference standard that enables ERCOT MDAS to maintain the IDR data on Central Prevailing Time (CPT). The meter clock shall be synchronized to within +/- 1% of the Settlement Interval when compared with the National Institute of Standards and Technology (NIST) Atomic Clock. ERCOT shall perform the time synchronization for meters at the time of the interrogation if the meter is outside tolerance; and

(h) Divide each hour into Settlement Intervals ending as follows:

XX:15:00
XX:30:00
XX:45:00
XX:00:00

10.9.2 TSP or DSP Metered Entities

(1) IDRs used for settlement of TSP or DSP Metered Entities shall:

(a) Capture energy consumption in increments consistent with, or in fractions of, ERCOT-defined settlement time interval;

(b) Provide interval data on a schedule that supports the requirements of final Settlement;

(c) Have battery or other energy-storage back-up to maintain time during power outages;

(d) Have time synchronization capability;

(e) Maintain meter clocks on a time reference that enables the TSP or DSP to submit data on the CPT. The meter clock shall be synchronized to within at least +/- 5% of the Settlement Interval when compared to the NIST Atomic Clock;

(f) Have data aggregated to the appropriate Settlement Interval time block by the TSP or DSP prior to the data being sent to ERCOT if recorded at increments less than the ERCOT defined Settlement Interval;

(g) Be able to capture energy in increments of five minutes (excluding memory allocation) for new and replacement IDRs used for Settlement;

(h) Divide each hour into Settlement Intervals ending as follows:

XX:15:00
XX:30:00
XX:45:00
XX:00:00

(i) IDR data submitted to ERCOT for Operating Days January 1, 2003, or later must contain only whole days with start times beginning at 0000 and stop times ending at 2359.

10.9.3 Failure to Comply with Standards

(1) If the TSP or DSP fails to comply with the standards for EPS Metering Facilities referred to in this Section and the SMOG, then ERCOT shall notify the Public Utility Commission of Texas (PUCT) or the appropriate Governmental Authority.

10.10 Security of Meter Data

10.10.1 EPS Meters

(1) A Transmission Service Provider (TSP) or Distribution Service Provider (DSP) is responsible for data security of the ERCOT-Polled Settlement (EPS) Metering Facilities on their system. This responsibility extends to third-party contracts and access to EPS Metering Facilities.

(2) A TSP, DSP or any Entity authorized to poll EPS Meters may not issue any EPS Meter programming passwords to any Market Participant.

10.10.1.1 TSP and DSP Data Security Responsibilities

(1) Each TSP and DSP shall:

(a) Maintain and modify the passwords for programming and read access to EPS Meters;

(b) Provide the appropriate password access to ERCOT, which will allow ERCOT to synchronize the meter clock;

(c) Establish any other security requirements for accessing the EPS Meters so as to ensure the security of those meters and their meter data;

(d) Coordinate any EPS Meter programming parameter changes with ERCOT according to this Section, including informing the Load or Resource Entity of any changes to the meter;

(e) Upon request of the Resource Entity that represents an EPS metered facility, provide the EPS meter "read only" password to such Resource Entity for such facility and other EPS metered facility required to calculate their Qualified Scheduling Entity (QSE) Load, to the extent that such provision does not violate the Customer service and protection provisions of the Public Utility Commission of Texas (PUCT) Substantive Rules; and

(f) Modify the "read only" password for EPS meters when a Resource Entity that represents a facility requests a change due to data security reasons, provided that such modification does not violate the Customer service and protection provisions of the PUCT Substantive Rules.

10.10.1.2 ERCOT Data Security Responsibilities

(1) ERCOT may request that TSP or DSP alter the password and other requirements for accessing EPS Meters, as it deems necessary.

10.10.1.3 Resource Entity Data Security Responsibilities

(1) A Resource Entity must request that the TSP or DSP modify the EPS Meter "read only" password for a facility when the Resource Entity relationships that affect EPS Meter data security change. Such request must include the reason for the request.

10.10.1.4 Third Party Access Withdrawn

(1) If, in the reasonable opinion of ERCOT, access granted to a third party interferes with or impedes ERCOT's ability to poll any EPS Meter, ERCOT may require immediate withdrawal of any access granted to such third party. Separate access through additional communications ports may be allowed so long as it does not interfere with ERCOT's ability to communicate with the meter.

10.10.1.5 Meter Site Security

(1) EPS Metering Facilities and secondary devices that could have any impact on the performance of the EPS Metering Facilities must be sealed to the extent practicable.

(2) ERCOT shall provide each TSP and DSP with uniquely numbered seals to be used by the TSP or DSP EPS Meter Inspector to seal EPS Meters and EPS Meter test switches. Procedures for seal use shall be in accordance with this Section and the SMOG.

10.10.2 TSP or DSP Metered Entities

(1) Security for TSP and DSP polled meters and meter data shall be the responsibility of the TSP or DSP. Each TSP and DSP shall maintain polled meters in accordance with applicable Governmental Authority rules and regulations. The TSP and DSP shall ensure that only Customer-approved Market Participants have access to the Customer meter.

10.11 Validating, Editing, and Estimating of Meter Data

10.11.1 EPS Meters

(1) The raw meter data that ERCOT retrieves from ERCOT-Polled Settlement (EPS) Meters must be processed by Meter Data Acquisition System (MDAS) using the Validating, Editing, and Estimating (VEE) procedures published in Section 11, Data Acquisition and Aggregation, and the Settlement Metering Operating Guide (SMOG) in order to produce Settlement Quality Meter Data. During periods for which no primary EPS Meter data is available, ERCOT shall use the backup meter data or substitute estimated usage data for that metered Entity using estimation procedures referred to in these Protocols and the SMOG. This data shall be used by ERCOT in its settlement and billing process.

10.11.2 Obligation to Assist

(1) At the request of ERCOT, a Transmission Service Provider (TSP), Distribution Service Provider (DSP) and Market Participant shall promptly assist ERCOT in correcting or replacing defective data from EPS Meters and in detecting and correcting underlying causes for such defects. Such assistance shall be rendered in a timely manner so that the settlement process is not delayed.

10.11.3 TSP or DSP Settlement Meters

(1) The TSP and DSP shall provide ERCOT with Settlement Quality Meter Data for the TSP or DSP Settlement Meters on its system and shall ensure that at a minimum the Validation, Editing and Estimating (VEE) requirements as specified in the Uniform Business Practices (UBP) standard for VEE have been properly performed on such data.

ERCOT shall not perform any VEE on the Settlement Quality Meter Data it receives from TSP or DSP.

(2) The following UBP manual validation processes are exempt for Interval Data:

(a) Spike Check; and

(b) Reactive channel check for kWh data.

10.12 Communications

10.12.1 ERCOT Acquisition of ERCOT-Polled Settlement (EPS) Meter Data

(1) ERCOT shall acquire ERCOT-Polled Settlement (EPS) Meter data via the following communication links:

(a) ERCOT private communication network established by ERCOT for ERCOT Real-Time metered Entities; or

(b) Other ERCOT-approved communication technology provided by the Transmission Service Provider (TSP) or Distribution Service Provider (DSP).

10.12.2 TSP or DSP Meter Data Submittal to ERCOT

(1) TSP and DSPs shall submit meter consumption data to ERCOT through a standard data interface into the Meter Data Acquisition System (MDAS). In order to submit meter consumption data, a TSP or DSP shall use an automated system with an ERCOT-approved and tested interface to MDAS.

10.12.3 ERCOT Distribution of Settlement Quality Meter Data

(1) ERCOT shall distribute Settlement Quality Meter Data to Market Participants:

(a) Whenever a TSP or DSP submits meter consumption data to ERCOT via a Texas Standard Electronic Transaction (TX SET), ERCOT will forward the consumption data and other information for the Electric Service Identifiers (ESI IDs) to the Competitive Retailer (CR) indicated in the transaction. ERCOT relies upon the TSP or DSP to ensure that the CR included in the transaction is the appropriate CR for the meter data timeframe. ERCOT does not further validate the accuracy of the CR indicated.

(b) Whenever a TSP or DSP submits meter data to ERCOT via an ERCOT specified file format for Advanced Meters, upon certified request by a Market Participant, ERCOT shall make that data available to the Market Participant via Market Information System (MIS) Certified Area.

(c) On Request – A Market Participant may submit an electronic request via the MIS Certified Area for specific meter consumption data. ERCOT will receive and validate the request and, if appropriate, automatically forward the appropriate information to the Market Participant.

10.13 Meter Identification

(1) The device id used to identify an ERCOT-Polled Settlement (EPS) Meter shall be unique for such meters on the ERCOT System. ERCOT shall maintain a master list of device ids and shall notify each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) if the device id selected has been used elsewhere in Meter Data Acquisition System (MDAS).

10.14 Exemptions from Compliance to Metering Protocols

10.14.1 Authority to Grant Exemptions

(1) ERCOT may grant on a case by case basis, exemptions from compliance on a temporary basis until new arrangements can be completed in accordance with the guidelines as listed below. Any permanent exemption to this Section requires approval by the Technical Advisory Committee (TAC) and the ERCOT Board. Any permanent exemption shall be subject to periodic review and revocation by the ERCOT Board.

10.14.2 Guidelines for Granting Temporary Exemptions

(1) ERCOT shall use the following process when considering applications for temporary exemptions from compliance with this Section and the Settlement Metering Operating Guide (SMOG).

(a) Publication of Guidelines: ERCOT shall post on the ERCOT website the general guidelines that it will use when considering applications for exemptions within five Business Days of a change of guidelines, so as to achieve consistency in its reasoning and decision-making and to give prospective applicants an indication of whether an application for exemption may be considered favorably.

(b) Publication of Decision: ERCOT shall post on the ERCOT website the application for exemption and whether the application was approved or rejected by ERCOT and the reasons for rejecting the application, if applicable, on a quarterly basis.

10.14.3 Procedure for Applying for Exemptions

(1) All applications to ERCOT for exemptions from compliance with the requirements of this Section must be submitted in writing. ERCOT shall confirm receipt of an application

within three Business Days of receipt. For temporary exemptions, ERCOT shall decide whether to grant or reject the exemption within 45 Business Days of receipt. For permanent exemptions, ERCOT shall forward the application to TAC for review at the next scheduled meeting for which appropriate Notice can be made. At any time during the application process, ERCOT may require the applicant to provide additional information in support of its application.

(2) The applicant shall provide such additional information to ERCOT within five Business Days of receiving the request or within such other period as ERCOT may specify. If ERCOT requests additional information more than 40 Business Days after the date on which it received the application, ERCOT shall have an additional seven Business Days after receiving that additional information in which to consider the application. If the applicant does not provide the additional information requested, then ERCOT shall reject the application, in which case it will notify the applicant that its application has been rejected for failure to provide the additional information.

10.14.3.1 Information to be Included in the Application

(1) The application for exemption to ERCOT shall include:

(a) A detailed description of the exemption sought. including specific reference to the relevant Section(s) of these Protocols or the SMOG authorizing ERCOT to grant the exemption, and the Metering Facilities to which the exemption will apply;

(b) A detailed statement of the reason for seeking the exemption, including any supporting documentation;

(c) Details of the Entity(s) to which the exemption will apply;

(d) Details of the location to which the exemption will apply;

(e) Details of the period of time for which the exemption will apply, including the proposed start and finish dates of that period; and

(f) Any other information requested by ERCOT.

ERCOT Nodal Protocols

Section 11: Data Acquisition and Aggregation

June 1, 2022

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11 DATA ACQUISITION AND AGGREGATION

11.1 Data Acquisition and Aggregation from ERCOT Polled Settlement Metered Entities

11.1.1 Overview

(1) ERCOT will collect interval data from all ERCOT-Polled Settlement (EPS) metered Entities according to Section 10, Metering. Collection of data from EPS metered Entities will be done via the Meter Data Acquisition System (MDAS). This data will be validated, edited, estimated, adjusted, netted, loss corrected, split, and aggregated as necessary to provide the required Settlement inputs.

11.1.2 ERCOT Polled Settlement Meter Data Collection

(1) ERCOT will perform remote interrogation of EPS metered Entities to provide the necessary data for the Settlement process. Upon initiation of connection with the meter, the MDAS will verify that the meter's internal Interval Data Recorder (IDR) protocol (Translation Interface Module setting) and the device identifier programmed into the IDR match the master file database stored in the MDAS. If remote-polling fails for any reason, ERCOT will work closely with the Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) to resolve data collection problems within the time frame defined in Section 10, Metering.

11.1.3 ERCOT Polled Settlement Meter Time Synchronization

(1) ERCOT will update the clock of any EPS meter that falls outside the threshold defined in Section 10, Metering of these Protocols. ERCOT will notify the TSP and/or DSP regarding any meter that is determined to be inconsistent in its timekeeping function. The TSP and/or DSP will facilitate correction of this problem within the time frame detailed in Section 10.

11.1.4 ERCOT Polled Settlement Meter Data Validation, Editing, and Estimation

(1) After EPS time synchronization has been completed and interval meter data has been retrieved, ERCOT will determine if the data is valid. The validation process will include, but not be limited to, the following tests:

(a) Flagging of intervals with missing data;

(b) Exception reporting if the total number of zero values for any channel exceeds the tolerance limit;

(c) Exception reporting if the total number of power outage intervals exceeds the tolerance limit;

(d) Channel level exception reporting if any single interval breaches the upper or lower threshold of the limit;

(e) Channel level validation of the percent change between two consecutive intervals being greater than the established tolerance limit;

(f) Data overlap validation test, which rejects validations when the current interrogation of data overlaps data previously collected;

(g) Channel level energy tolerance test, which reports exceptions of total energy accumulated from the interval data not being equivalent to the energy calculated from the meter register's start and stop readings;

(h) Validation that the number of expected intervals equals the number of actual intervals collected during the interrogation process; and

(i) Validation of data between primary, backup and check meters where available.

(2) ERCOT will perform editing and estimation of EPS meter data according to Section 10, Metering. The validation process occurs each time data is collected from a meter.

11.1.5 Loss Compensation of ERCOT Polled Settlement Meter Data

(1) Adjustments will be made to actual metered consumption to accommodate the energy consumption related to line and transformation losses to the Point of Interconnection (POI) with the ERCOT Transmission Grid in accordance with Section 10.3.2.2, Loss Compensation of EPS Meter Data. These adjustments are intended specifically to correct the metered consumption when the meter is not located at the POI with the ERCOT Transmission Grid.

(2) The preferred method for loss compensation and correction is by programming of the meter. Recognizing that some meters may not have the ability to perform internal compensation computations, ERCOT's Data Aggregation System (DAS) will have the ability to perform approved loss compensation as necessary.

(3) TSPs and/or DSPs requesting loss compensation for a specific meter will comply with Section 10, Metering, and the Settlement Metering Operating Guide (SMOG). ERCOT will provide a compensation mechanism based upon a single percentage value submitted by the TSP and/or DSP and approved by ERCOT. The loss compensation percentage value will remain in place and will be applied to all intervals of data until such time as the TSP and/or DSP submits, and ERCOT approves, revised loss compensation values. The loss compensation percentage values should not be changed more than once annually.

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 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) 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.

[NPRR995: Insert paragraphs (6) and (7) below upon system implementation:]

(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.

(7) 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.

11.1.7 ERCOT Polled Settlement Generation Meter Splitting

(1) ERCOT will apply any approved splitting schemes to partition generation production and auxiliary Load when the unit is not in operation in accordance with Section 10, Metering of these Protocols.

11.1.8 Correction of ERCOT Polled Settlement Meter Data for Non-Opt-In Transmission Losses

(1) ERCOT will correct the total Load of EPS meters for Non-Opt-In Entities (NOIEs) that have transmission behind the Settlement meters and are connected to the ERCOT Transmission Grid via bi-directional metering for actual Transmission Losses according to Section 13, Transmission and Distribution Losses. ERCOT will populate Settlement Interval Load data for NOIEs into data sets to be used in the Load aggregation process. NOIEs will receive extract Load data via the Market Information System (MIS) Certified Area.

11.1.9 Treatment of Non-Opt-In Entity or External Load Serving Entity Radially Connected Entities

(1) At NOIE or External Load Serving Entity (ELSE) metering points for which the TSP and/or DSP is supplying data to ERCOT, the interval Load data that is not bi-directional will have each point of delivery treated as an individual Electric Service Identifier (ESI ID).

11.1.10 Treatment of ERCOT Polled Settlement Load Data

(1) For EPS metering that ERCOT is populating ESI ID Load data, ERCOT will:

(a) Utilize the data for all Settlement calculations and reports;

(b) Provide the TSP and/or DSP and Load Serving Entity (LSE) with daily kWh consumption information in accordance with Texas Standard Electronic Transaction (Texas SET) 867_03, Monthly Usage, for interval data upon completion of the Data Aggregation process for the Settlement day. Data changes during Settlement runs subsequent to the most current Settlement run will result in an additional Texas SET 867_03 being provided to the TSP and/or DSP and LSE. The TSP, DSP, or LSE may request not to receive the consumption information. Such a request must be submitted by the applicable Authorized Representative or Backup Authorized Representative;

(c) Accommodate retail switching via the standard switching process and timelines;

(d) Be identified as the Meter Reading Entity (MRE); and

(e) Make ESI ID interval data available to the TSP and/or DSP and LSE via an extract.

(2) The ERCOT read ESI ID data extract will:

(a) Select all ERCOT read ESI IDs for the Market Participant; and

(b) Provide interval data as populated by ERCOT for each channel associated to an ESI ID.

11.1.11 Treatment of ERCOT Polled Settlement Resource ID Data

(1) For EPS Resource ID (RID) data, ERCOT will:

(a) Be identified as the MRE;

(b) Model and populate data to appropriate channels such that netting and aggregation conform to the ERCOT Protocol requirements; and

(c) Make RID interval and Supervisory Control and Data Acquisition (SCADA) interval data available to the associated Qualified Scheduling Entity (QSE), TSP and/or DSP, Resource Entity, and LSE via an extract.

(2) The ERCOT RID data extract will:

(a) Select all ERCOT read RIDs for the Market Participant;

(b) Provide interval data as populated by ERCOT for each channel associated to a RID;

(c) Provide the interval data to the TSPs and/or DSPs no later than noon on the tenth Business Day after ERCOT reads the EPS meter;

(d) Provide interval data for Load and generation to TSPs and/or DSPs in accordance with Section 3.11.5, Transmission Service Provider and Distribution Service Provider Access to Interval Data; and

(e) Whenever ERCOT makes an edit to data previously provided to the TSP and/or DSP, ERCOT shall provide the revised data to the TSP and/or DSP by noon of the tenth Business Day after the edit is made.

11.1.12 Treatment of ERCOT-Polled Settlement Energy Storage Resource Load Data

(1) For EPS data associated with WSL and Non-WSL ESR Charging Load, ERCOT will:

(a) Be identified as the MRE; and

(b) Model and populate data to appropriate channels such that netting and aggregation conform to the ERCOT Protocol requirements.

11.2 Data Acquisition from Transmission Service Providers and/or Distribution Service Providers

11.2.1 Overview

(1) This Section addresses the manner in which ERCOT will receive and validate data from the Transmission Service Providers (TSPs) and /or Distribution Service Providers (DSPs) regarding usage for Generation Resources and Load from TSP and/or DSP metered Entities as defined in Section 10, Metering.

[NPRR1002: Replace paragraph (1) above with the following upon system implementation:]

(1) This Section addresses the manner in which ERCOT will receive and validate data from the Transmission Service Providers (TSPs) and /or Distribution Service Providers (DSPs) regarding generation and Load from TSP and/or DSP metered Entities as defined in Section 10, Metering.

11.2.2 Data Provision and Verification of Non ERCOT Polled Settlement Metered Points

(1) The TSP and/or DSP will provide data for TSP and/or DSP metered Entities as defined in Section 10, Metering, of these Protocols.

(2) The TSP and/or DSP will provide data in accordance with the TSP and/or DSP meter data responsibilities detailed in Section 10 and will conform to data formats specified in Section 19, Texas Standard Electronic Transaction.

(3) ERCOT will:

(a) Provide the TSP and/or DSP a notification of successful/unsuccessful data transfer for the Texas Standard Electronic Transaction (TX SET) meter data submitted. At the Electric Service Identifier (ESI ID) level, the TSP and/or DSP will be notified of successful and unsuccessful validations;

(b) Validate that the correct TSP and/or DSP is submitting meter consumption data on an individual ESI ID basis. At the ESI ID level, the TSP and/or DSP will be notified of unsuccessful validations;

(c) Provide a report to the TSP and/or DSP listing each ESI ID for which ERCOT has not received consumption data for 38 days; and

(d) Synchronize the Data Aggregation System (DAS) data with the Customer registration system on a daily basis to ensure the appropriate relationship between the ESI ID, Load Serving Entity (LSE) and/or Resource Entity, and the meter. DAS will provide versioning to ensure ESI ID characteristic changes are time stamped.

11.3 Electric Service Identifier Synchronization

11.3.1 Electric Service Identifier Service History and Usage

(1) On a daily basis, ERCOT shall provide incremental updates to Electric Service Identifier (ESI ID) service history and usage information to Load Serving Entities (LSEs), Meter Reading Entities (MREs), and Transmission Service Providers (TSPs) and/or Distribution Service Providers (DSPs). ESI ID service history includes ESI ID relationships and ESI ID characteristics.

11.3.2 Variance Process

(1) Any LSE, MRE, TSP or DSP that contests the accuracy of ESI ID service history and usage information maintained by ERCOT shall file a variance in the manner specified by the Retail Market Guide. The variance shall be processed in the manner specified in the Retail Market Guide, and ERCOT and Market Participants that are or may be affected by the variance shall comply with the provisions of the Retail Market Guide as they relate to the variance.

11.3.3 Alternative Dispute Resolution

(1) An LSE, MRE, TSP or DSP may seek correction of ESI ID service history/usage information and resettlement pursuant to the provisions of Section 20, Alternative Dispute Resolution Procedure.

11.4 Load Data Aggregation

(1) Data Aggregation is the process of netting, grouping and summing Load consumption data, applying appropriate profiles, Transmission Loss Factors (TLFs) and Distribution Loss Factors (DLFs) and calculating and allocating Unaccounted For Energy (UFE) to determine each Qualified Scheduling Entity (QSE) and/or Load Serving Entity (LSE) responsibility by Settlement Interval by Settlement Point and by other prescribed aggregation determinants. The process of aggregating Load data provides the determinants that allow the Settlement to occur.

11.4.1 Estimation of Missing Data

(1) The Data Aggregation System (DAS) will perform estimation of missing interval and non-interval retail Load meter consumption data for use in Settlement when actual meter consumption data is unavailable.

11.4.2 Non-Interval Missing Consumption Data Estimation

(1) The DAS will distinguish each Electric Service Identifier (ESI ID) for which consumption data has not been received for the Operating Day. Non-interval ESI ID locations for which no actual consumption exists for the specified Operating Day will be pre-aggregated by like components which may include but are not limited to the following sets:

(a) QSE;

(b) LSE;

(c) Settlement Point;

(d) UFE zone;

(e) Profile ID;

(f) DLF code;

(g) Transmission Service Provider (TSP) and /or Distribution Service Provider (DSP);

(h) Read start date (reading from date); and

(i) Read stop date (reading to date).

(2) Estimates of missing data are based on Profile ID, which includes:

(a) Load Profile Type;

(b) Weather Zone;

(c) Meter type;

(d) Weather sensitivity; and

(e) Time Of Use Schedule (TOUS).

(3) Profile application will take aggregated non-interval consumption data and apply the Load Profile in order to create interval consumption data. Profiled non-interval data is calculated by dividing the aggregated ESI ID’s total kWh for a specific time period

(usually a month) by the profile class' kWh for the same specific time period and scaling the Load Profile for that same specific Operating Day by the resulting value to provide the profiled non-interval consumption data.

$$\mathbf{PND}_{\textit{Operating Day}} = (\Sigma \mathbf{Actual\ KWH}_{\textit{Specific Time Period}} / \Sigma \mathbf{CP\ KWH}_{\textit{Specific Time Period}}) * \mathbf{LP}_{\textit{Operating Day}}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
PND		Profiled non-interval data.
CP		Class profile.
LP	kWh	Load Profile (daily interval data set).

(4) Any active ESI ID on the Operating Day being settled for which ERCOT does not have a meter read within 12 months of the Operating Day will not have a usage estimate applied to its Load Profile. That is, the estimate for these Customers will be their assigned profile without any scaling factor applied.

11.4.3 Interval Consumption Data Estimation

(1) ERCOT will estimate all ESI IDs with Interval Data Recorders (IDRs) for which consumption data has not been received for the Operating Day. The method for estimating interval data for ESI IDs with IDR Meters is a "Weather Response Informed Proxy Day" technique. This approach seeks to increase estimation accuracy by segmenting ESI IDs with IDR Meters into two groups based on a known indicator of Load, i.e. weather. The classification of ESI IDs with IDR Meters into a weather-sensitive group and a non-weather-sensitive group determines the proxy day method used for estimation purposes. The proxy day estimation method for each group captures the factors that best predict the ESI ID-specific Load shape for the Operating Day.

(2) The Weather Sensitive Proxy Day Method will be used for estimating interval data for ESI IDs with Advanced Meters or Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ IDRs.

11.4.3.1 Weather Responsiveness Determination

(1) ERCOT shall perform the weather responsiveness test for all ESI IDs with IDR Meters as specified below.

(2) For each ESI ID with an IDR Meter, two variables shall be calculated for each Business Day on which the ESI ID is active and for which actual interval data is available during the time period (June 1st - September 30th) immediately preceding the date the test is run:

(a) Daily kWh; and

(b) Average Weather Zone daily dry bulb temperature.

Average Weather Zone Daily Dry Bulb Temperature = ((MAX + MIN) / 2)

The above variables are defined as follows:

Variable	Unit	Description
MAX		Maximum Weather Zone daily dry bulb temperature.
MIN		Minimum Weather Zone daily dry bulb temperature.

(3) For each ESI ID an R-square (Pearson Product Moment Coefficient of Determination) shall be calculated between these two variables, and all ESI IDs with R-square greater than or equal to 0.6 shall be classified as weather sensitive and all ESI IDs with an R-square less than 0.6 shall be classified as non-weather sensitive.

(4) The weather responsiveness determination shall be performed annually between November 1st and November 15th.

(5) No later than November 20th, ERCOT shall produce a report that contains the ESI IDs that require profile code modifications as a result of the weather responsiveness test. This report shall be published to Market Participants in a data extract via the Market Information System (MIS) Certified Area by November 20th.

(6) If an ESI ID is inactive or de-energized at the time the weather responsiveness test is performed, or if it is de-energized for 50% or more of the time period beginning June 1st and ending September 30th, it shall retain its current weather sensitivity classification and shall not be re-evaluated until the following year.

(7) If, for a specific ESI ID, 50% or more of the data required for the calculations described above is missing, the ESI ID shall retain its current weather sensitivity classification.

(8) Beginning on December 1st, and continuing monthly thereafter until May of the following year, ERCOT shall repeat the weather responsiveness test. These tests shall be limited to ESI IDs that had some missing data during the previous time period when the most recent weather responsiveness test was performed. As above, ERCOT shall produce a report that contains the ESI IDs requiring profile code modifications and shall publish the report via the MIS Certified Area.

(9) TSPs and/or DSPs shall successfully complete at least 99% of the weather sensitivity code modifications (Load Profile ID changes) no later than 90 days after the ESI ID

appears on the ERCOT report. Load Profile ID changes shall be effective as of the most current meter read date.

(10) On a monthly basis, ERCOT shall produce a report of ESI IDs that are overdue in having their weather sensitivity codes modified by the above referenced tests.

(11) As a part of the Load Profile Class assignment, TSPs and/or DSPs will assign a non-weather sensitive classification to all newly installed IDR Meters and a weather sensitive classification to all Advanced Meters and MOU/EC Non-BUSIDRRQ IDRs.

11.4.3.2 Weather Sensitive Proxy Day Method

(1) For ESI IDs designated as Weather Sensitive IDR (WSIDR), ERCOT will use this weather-sensitive proxy day selection method. ESI IDs within the same Weather Zone will be grouped together. The proxy days will be the same for all ESI IDs within each of the Weather Zones. This method incorporates the following:

(a) To determine eligible proxy days, select all days (of matching weekday/weekend day type and time period) within five degrees of the maximum temperature of the target Operating Day based on the previous 365 days and then limit the selection to those days that have their maximum temperatures occurring within two hours of the maximum temperature hour of occurrence of the Operating Day. The maximum temperature separation criterion provides initial assurance that the eligible day will have a similar diurnal temperature pattern as the target Settlement Operating Day.

(b) Perform two tests on each potential proxy day identified in item (a) above:

(i) Temperature magnitude test sums the squared differences between the hourly temperatures of the target Operating Day and the hourly temperatures of the potential proxy day; and

(ii) Temperature shape test calculates the incremental change in temperature from hour to hour during the day and sums the squared differences between the corresponding values of the target Operating Day and the potential proxy day.

(c) Each potential proxy day for each test described in item (b) above is ranked in ascending order based on the sum of squared differences.

(d) A final ranking is performed with the temperature magnitude test weighted more heavily than the shape test. The weighting factors are 70% and 30%.

(e) Select the top three ranked eligible days.

(f) For each ESI ID, do the following:

(i) Use the top ranked proxy day for the target Operating Day, if available;

(ii) If the top ranked proxy day data is not available, use the second ranked proxy day data as the estimate;

(iii) If the second ranked proxy day data is not available, use the third proxy day;

(iv) If no data is available for any of the proxy days selected, then default to the non-weather sensitive proxy day selection list; and

(v) If still no estimate is generated when the non-weather sensitive method is used, the IDR data will be estimated using the default profile class average profile for the Operating Day.

11.4.3.3 Non-Weather Sensitive Proxy Day Method

(1) For ESI IDs designated as Non-Weather Sensitive IDR (NWSIDR), ERCOT will use a method for proxy day determination. This method incorporates the following:

(a) Use the most recent proxy day for which data is available as the estimate for the target Operating Day. From historical ESI ID specific interval data, choose the most recent occurrence of the appropriate day of the week (Sunday, Monday, Tuesday, Wednesday, Thursday, Friday, Saturday) corresponding to the day of the week of the Operating Day (holidays are treated as Sundays) within the most recent 12 months of the Operating Day; or

(b) If there is no historic interval data available according to item (a) above, the IDR data will be estimated using the default profile assigned to the ESI ID for the Operating Day. If non-interval consumption data with a meter read within 12 months of the Operating Day is available, and if the ESI ID was profiled with a non-interval meter data type code within 90 days of the Operating Day, the default profile shall be estimated and/or scaled in accordance with Section 11.4.2, Non-Interval Missing Consumption Data Estimation.

11.4.3.4 Interval Data Recorder Estimation Reporting

(1) ERCOT shall produce a report detailing the proxy day selection list for both NWSIDR and WSIDR methodologies. This report will be made available to Market Participants on a daily basis.

11.4.4 Data Aggregation Processing for Actual Data

(1) The DAS will apply backcasted profiles to aggregated actual non-interval consumption data for use in Settlement when actual meter consumption data is available. IDR ESI IDs for which actual data exists will be used directly in the Data Aggregation process.

11.4.4.1 Application of Profiles to Non-Interval Data

(1) Non-Interval ESI ID locations for which actual consumption exists for the specified Operating Day will be pre-aggregated by like components which may include but are not limited to the following sets:

(a) QSE;

(b) LSE;

(c) Settlement Point;

(d) UFE zone;

(e) Profile ID;

(f) DLF code;

(g) TSP and/or DSP;

(h) Read start date (reading from date); and

(i) Read stop date (reading to date).

(2) Profile application will take aggregated non-interval consumption data and apply the Load Profile in order to create interval consumption data. Profiled non-interval data is calculated by dividing the aggregated ESI ID's total kWh for a specific time period (usually a month) by the profile class' kWh for the same specific time period and scaling the Load Profile for that same specific Operating Day by the resulting value to provide the profiled non-interval consumption data.

$$\mathbf{PND}_{\textit{Operating Day}} = (\Sigma \mathbf{Actual\ KWH}_{\textit{Specific Time Period}} / \Sigma \mathbf{CP\ KWH}_{\textit{Specific Time Period}}) * \mathbf{LP}_{\textit{Operating Day}}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
PND		Profiled non-interval data.
CP		Class profile.

LP	kWh	Load Profile (daily interval data set).

11.4.4.2 Load Reduction for Excess PhotoVoltaic and Wind Distributed Renewable Generation

(1) Adjusted Metered Load (AML) for ESI IDs with PhotoVoltaic (PV) generation shall be adjusted as follows:

For ESI IDs with non-IDRs installed, AML shall be reduced for excess generation from ESI IDs with PV generation equal to or lower than the Distributed Generation (DG) registration threshold behind the meter where there is a meter that measures excess energy flow into the ERCOT System in a separate register. Only ESI IDs that have been assigned a PV profile segment as specified in Load Profiling Guide Appendix D, Profile Decision Tree, shall be eligible for this reduction.

Intervals beginning 1100 and ending 1500 Central Prevailing Time (CPT) (spanning (16) 15-minute intervals) shall be reduced by the following amount:

$$\mathbf{PV\_adjust}_{\boldsymbol{i}} = \mathbf{kWh\_gen / (read\_days * 16)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
PV_adjust_i	kWh	Reduction for PV excess generation for interval *i*.
kWh_gen	kWh	Actual (measured) kWh flowing into the Distribution System (out-flow from the Premise).
read_days	days	Number of days in meter read period.

(2) AML for ESI IDs with wind generation shall be adjusted as follows:

For ESI IDs with non-IDRs installed, AML shall be reduced for excess generation from ESI IDs with wind generation equal to or lower than the DG registration threshold behind the meter where there is a meter that measures excess energy flow into the ERCOT System in a separate register. Only ESI IDs that have been assigned a wind profile segment as specified in the Load Profiling Guide Appendix D, shall be eligible for this reduction.

Intervals beginning 0800 and ending 2000 CPT (spanning (48) 15-minute intervals) shall be reduced by the following amount:

$$\text{Wind\_adjust} = \text{kWh\_gen} * .65 / (\text{read\_days} * 48)$$

All other intervals in the day (the remaining 48 intervals) shall be reduced by the following amount:

$$\text{Wind\_adjust} = \text{kWh\_gen} * .35 / ((\text{read\_days} * 48) + \text{DST adjust})$$

Where:

Variable	Unit	Description
$wind\_adjust_i$	kWh	Reduction for wind excess generation for interval *i.*
kWh_gen	kWh	Actual (measured) kWh flowing into the Distribution System (out-flow from the Premise).
read_days	days	Number of days in meter read period.
DST adjust	N/A	Daylight Savings Time Adjustment: Spring DST = -4; Fall DST = 4.

(3) The excess generation adjustments for ESI IDs, which have PV or wind generation of equal to or lower than the DG registration threshold, as described in Section 16.5, Registration of a Resource Entity, behind the meter and that have an Advanced Metering System (AMS) integrated meter or MOU/EC Non-BUSIDRRQ IDR that measures the excess energy flow into the ERCOT System in 15-minute intervals, shall be determined using the actual 15-minute interval data, if available.

11.4.4.3 Load Reduction for Excess from Other Distributed Generation

(1) AML for ESI IDs with DG that is neither PV nor wind shall be adjusted as follows:

For ESI IDs with non-IDRs installed, AML shall be reduced for excess generation from ESI IDs with DG generation of equal to or lower than the DG registration threshold behind the meter where there is a meter that measures excess energy flow into the ERCOT System in a separate register. Only ESI IDs that have been assigned a DG profile segment as specified in Load Profiling Guide Appendix D, Profile Decision Tree, shall be eligible for this reduction.

All intervals in the meter read period shall be reduced by the following amount:

$$\mathbf{DG\ \_adjust}_{\,i} = \mathbf{kWh\_gen / read\_ints}$$

The above variables are defined as follows:

Variable	Unit	Description
DG_adjust_i	kWh	Reduction for excess DG for interval *i*.
kWh_gen	kWh	Actual (measured) kWh flowing into the Distribution System (out-flow from the Premise).
read_ints	Intervals	Number of 15-minute intervals in the meter read period.

(2) The energy reduction adjustment for ESI IDs, which have DG equal to or lower than the DG registration threshold behind the meter and have an AMS integrated meter that measures the excess energy flow into the ERCOT System in 15-minute intervals, shall be determined using the actual 15-minute interval data, if available.

11.4.5 Adjustment of Consumption Data for Losses

(1) The ERCOT DAS shall adjust consumption data for Transmission Losses and Distribution Losses. The sources of data used in this process are:

(a) Profiled estimated non-interval data;

(b) Estimated proxy day interval data;

(c) Profiled actual non-interval data;

(d) Actual interval data;

(e) DLFs; and

(f) TLFs (average ERCOT-wide).

(2) ERCOT will apply DLFs to aggregate levels of Load data in accordance with Section 13, Transmission and Distribution Losses. Aggregated Loads will be adjusted for Distribution Losses based upon DLF code correlated to the DLF for each TSP and/or DSP. Loads that are transmission connected or that are settled at transmission level will not be allocated distribution level losses. Intervals with negative Load will not be allocated distribution level losses.

$$\mathbf{NDLAL}_{\,\mathit{i\ Aggregated\ Group}} = \mathbf{Max\ (0,\ L}_{\,\mathit{i\ Aggregated\ Group}}\mathbf{)\ *\ 1\ /\ (1\text{-}\ DLF}_{\,\mathit{i\ Aggregated\ Group}}\mathbf{)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
i	None	Interval
NDLAL $_{i}$	MWh	Net Distribution Loss adjusted Load per interval
L $_{i}$	MWh	Load per interval
DLF $_{i}$	None	DLF (voltage code specific) per interval

(3) ERCOT will apply the ERCOT wide TLF to the net Distribution Loss adjusted Loads to produce a net loss adjusted aggregated Load value for each aggregation set. ERCOT wide TLFs will be developed in accordance with Section 13. Intervals with negative Load will not be allocated Transmission Losses.

$$\mathbf{NLAL}_{\,\mathit{i\ Aggregated\ Group}} = \mathbf{Max\ (0,\ NDLAL}_{\,\mathit{i\ Aggregated\ Group}}\mathbf{)\ *\ 1/\ (1\ -\ TLF}_{\,\mathit{i}}\mathbf{)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**

i	None	Interval
NDLAL $_i$	MWh	Net Distribution Loss adjusted Load per interval
NLAL $_i$	MWh	Net loss adjusted Load per interval
TLF $_i$	None	TLF (ERCOT wide factor) per interval

11.4.6 Unaccounted for Energy Calculation and Allocation

(1) The DAS shall adjust the net loss adjusted Load for each aggregated retail Load group for UFE. The Data Aggregation process will calculate the difference between net loss adjusted Load for the entire ERCOT System, which has been adjusted for Distribution Losses and Transmission Losses, and the total system Load (generation) in order to determine the total UFE. The calculated UFE for each Settlement Interval is then allocated to positive Loads. For the purpose of the UFE calculation, scheduled flow out of ERCOT on a Direct Current Tie (DC Tie) will be deemed as Load, and scheduled flow into ERCOT on a DC Tie will be deemed as generation.

11.4.6.1 Calculation of ERCOT-Wide Unaccounted For Energy

(1) The DAS will calculate ERCOT-wide UFE as the difference between the total ERCOT generation and the total Load, adjusted for losses in ERCOT during each Settlement Interval. UFE may be positive or negative in any single Settlement Interval.

$$\textbf{UFE}_{i}\ \textbf{(MWh)} = \textbf{ERCOT Generation}_{i\ Total} - \textbf{ERCOT Net Loss Adjusted Load}_{i\ Total}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
UFE $_i$	MWh	Total ERCOT system UFE per interval.
ERCOT Generation $_{i\ Total}$	MWh	Total ERCOT internal generation plus sum of approved ERCOT DC Tie imports.
ERCOT Net Loss Adjusted Load $_{i\ Total}$	MWh	Total ERCOT load plus Block Load Transfer (BLT) exports plus sum of approved DC Tie exports, adjusted for distribution and transmission losses. Exports associated with Oklaunion exempt QSEs do not receive distribution or transmission losses. ***[NPRR1054: Replace the description above with the following upon system implementation:]*** Total ERCOT load plus Block Load Transfer (BLT) exports plus sum of approved DC Tie exports, adjusted for distribution and transmission losses.
i		Interval

11.4.6.2 Allocation of Unaccounted For Energy

(1) ERCOT will allocate UFE to specific categories based upon adjusted Load Ratio Share. The adjusted Load Ratio Share will be determined using the following UFE category weighting factors:

(a) 0.0 - Transmission voltage level IDR Non-Opt-In Entities (NOIEs);

(b) 0.10 - Transmission voltage level IDR Premises;

(c) 0.50 - Distribution voltage level IDR Premises; and

(d) 1.00 - Distribution voltage level profiled Premises.

(2) The ERCOT DAS shall provide a mechanism to change the UFE category weighting factors for specific transition periods.

11.4.6.3 Unaccounted For Energy Allocation to Unaccounted For Energy Categories

(1) For each Premise category, and for each Settlement interval, the UFE allocated to each UFE category is calculated as follows:

$$\mathbf{UFE}_{\mathit{PRiz}} = \mathbf{UFE}_{\mathit{iz}} * [(\mathbf{f}_{\mathit{PRiz}} * \mathbf{L}_{\mathit{PRiz}}) / \mathbf{L}_{\mathit{UFEiz}}]$$

$$\mathbf{UFE}_{\mathit{IDRiz}} = \mathbf{UFE}_{\mathit{iz}} * [(\mathbf{f}_{\mathit{IDRiz}} * \mathbf{L}_{\mathit{IDRiz}}) / \mathbf{L}_{\mathit{UFEiz}}]$$

$$\mathbf{UFE}_{\mathit{TRiz}} = \mathbf{UFE}_{\mathit{iz}} * [(\mathbf{f}_{\mathit{TRiz}} * \mathbf{L}_{\mathit{TRiz}}) / \mathbf{L}_{\mathit{UFEiz}}]$$

$$\mathbf{UFE}_{\mathit{TNOIEiz}} = \mathbf{UFE}_{\mathit{iz}} * [(\mathbf{f}_{\mathit{TNOIEiz}} * \mathbf{L}_{\mathit{TNOIEiz}}) / \mathbf{L}_{\mathit{UFEiz}}]$$

$$\mathbf{L}_{\mathit{UFEiz}} = \mathbf{f}_{\mathit{PRiz}} * \mathbf{L}_{\mathit{PRiz}} + \mathbf{f}_{\mathit{IDRiz}} * \mathbf{L}_{\mathit{IDRiz}} + \mathbf{f}_{\mathit{TRiz}} * \mathbf{L}_{\mathit{TRiz}} + \mathbf{f}_{\mathit{TNOIEiz}} * \mathbf{L}_{\mathit{TNOIEiz}}$$

The above variables are defined as follows:

Variable	Unit	Description
UFE $_{PRiz}$		Amount of UFE allocated to profile category per interval per zone.
UFE $_{IDRiz}$		Amount of UFE allocated to IDR category per interval per zone.
UFE $_{TRiz}$		Amount of UFE allocated to transmission category per interval per zone.
UFE $_{TNOIEiz}$		Amount of UFE allocated to transmission voltage level NOIE category per interval per zone.
UFE $_{iz}$		Total ERCOT system UFE per interval per zone.
L $_{PRiz}$		Aggregate Load of profile category - adjusted for losses per interval per zone.

L_{IDRiz}		Aggregate Load of all IDR category - adjusted for losses per interval per zone.
L_{TRiz}		Aggregate Load of transmission category - adjusted for losses per interval per zone.
$L_{TNOIEiz}$		Aggregate Load of transmission level non opt-in category - adjusted for losses per interval per zone.
f_{PRiz}		Adjustment percentage for profiled Premises per interval per zone.
f_{IDRiz}		Adjustment percentage for IDR Premises per interval per zone.
f_{TRiz}		Adjustment percentage for transmission Premises per interval per zone.
$f_{TNOIEiz}$		Adjustment percentage for transmission voltage level non-opt-in Premises per interval per zone.
L_{UFEiz}		Adjusted total UFE allocation reference Load per interval per zone.

11.4.6.4 Unaccounted For Energy Allocation to Load Serving Entities within Unaccounted For Energy Categories

(1) The UFE allocated to each UFE category type is then allocated to the LSEs within each UFE category based upon each LSE’s share of the total Load for the UFE category.

$$\mathbf{UFE}_{\mathit{PRiz\ LSE}} = \mathbf{UFE}_{\mathit{PRiz}} * (\mathbf{Max}\ (0, \mathbf{L}_{\mathit{PRiz\ LSE}}) / \mathbf{L}_{\mathit{PRiz}})$$

$$\mathbf{UFE}_{\mathit{IDRiz\ LSE}} = \mathbf{UFE}_{\mathit{IDRiz}} * (\mathbf{Max}\ (0, \mathbf{L}_{\mathit{IDRiz\ LSE}}) / \mathbf{L}_{\mathit{IDRiz}})$$

$$\mathbf{UFE}_{\mathit{TRiz\ LSE}} = \mathbf{UFE}_{\mathit{TRiz}} * (\mathbf{Max}\ (0, \mathbf{L}_{\mathit{TRiz\ LSE}}) / \mathbf{L}_{\mathit{TRiz}})$$

$$\mathbf{UFE}_{\mathit{TNOIEiz\ LSE}} = \mathbf{UFE}_{\mathit{TNOIEiz}} * (\mathbf{Max}\ (0, \mathbf{L}_{\mathit{TNOIEiz\ LSE}}) / \mathbf{L}_{\mathit{TNOIEiz}})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
i	None	Interval.
z	None	Zone.
$UFE_{PRiz\ LSE}$	MWh	UFE allocated to LSE in UFE profile category per interval per zone.
$UFE_{IDRiz\ LSE}$	MWh	UFE allocated to LSE in UFE IDR category per interval per zone.
$UFE_{TRiz\ LSE}$	MWh	UFE allocated to LSE in UFE transmission category per interval per zone.
$UFE_{TNOIEiz\ LSE}$	MWh	UFE allocated to LSE in UFE transmission NOIE category per interval per zone.
UFE_{PRiz}	MWh	Amount of UFE allocated to profile category per interval per zone.

UFE_{IDRiz}	MWh	Amount of UFE allocated to IDR category per interval per zone.
UFE_{TRiz}	MWh	Amount of UFE allocated to transmission category per interval per zone.
$UFE_{TNOIEiz}$	MWh	Amount of UFE allocated to transmission voltage level NOIE category per interval per zone.
$L_{PRiz\ LSE}$	MWh	LSE Load in profile category - adjusted for losses per interval per zone.
$L_{IDRiz\ LSE}$	MWh	LSE Load in IDR category - adjusted for losses per interval per zone.
$L_{TRiz\ LSE}$	MWh	LSE Load in transmission category - adjusted for losses per interval per zone.
$L_{TNOIEiz\ LSE}$	MWh	LSE Load in transmission NOIE category - adjusted for losses per interval per zone.
L_{PRiz}	MWh	Aggregate Load of profile category - adjusted for losses per interval per zone.
L_{IDRiz}	MWh	Aggregate Load of all IDR category - adjusted for losses per interval per zone.
L_{TRiz}	MWh	Aggregate Load of transmission category - adjusted for losses per interval per zone
$L_{TNOIEiz}$	MWh	Aggregate Load of transmission level non opt-in category - adjusted for losses per interval per zone.

11.5 Data Aggregation

11.5.1 Aggregate Load Data

(1) Load data will be aggregated into distinct grouping and segments such as Load Serving Entity (LSE), Qualified Scheduling Entity (QSE), and Settlement Point, and provided to Settlement.

11.5.1.1 Aggregated Load Data Posting/Availability

(1) The following market-specific Load information will be made available by ERCOT to each Market Participant:

(a) LSE Load Ratio Share (LRS) data by ERCOT total;

(b) LSE Load values, by unique combination of QSE, Settlement Point, Unaccounted For Energy (UFE) zone, Load Profile Type, Distribution Loss Factor (DLF) code and Transmission Service Provider (TSP) and /or Distribution Service Provider (DSP);

(c) LSE Load plus allocation of Distribution Losses by unique combination of QSE, Settlement Point, UFE zone, Load Profile Type, DLF code and TSP and/or DSP;

(d) LSE Load plus allocation of Distribution Losses and Transmission Losses by unique combination of QSE, Settlement Point, UFE zone, Load Profile Type, DLF code and TSP and/or DSP; and

(e) LSE Load plus allocation of Distribution Losses, Transmission Losses, and UFE by unique combination of QSE, Settlement Point, UFE zone, Load Profile Type, DLF code and TSP and/or DSP.

(2) Each Market Participant will have access only to its own information and/or the information of the Entities which it represents. ERCOT will make the aforementioned data for each Settlement run available to Market Participants via the Market Information System (MIS) Certified Area within 48 hours of finalizing the data for Settlement statements.

11.5.1.2 TSP and/or DSP Load Data Posting/Availability

(1) ERCOT will post TSP and/or DSP Load plus allocation of Distribution Losses, Transmission Losses, and UFE, by TSP and/or DSP, to the MIS Secure Area.

(2) ERCOT will make the aforementioned data for each Settlement run type available to Market Participants via the MIS Secure Area within 48 hours of finalizing the data for Settlement Statements.

(3) ERCOT will post to the MIS Secure Area, a monthly report including TSP and/or DSP 15-minute interval Load data for each Operating Day adjusted to exclude Block Load Transfers (BLTs) or Direct Current Tie (DC Tie) exports.

11.5.2 Generation Meter Data Aggregation

(1) ERCOT will perform generation aggregation by the following distinct criteria sets:

(a) By UFE zone: This data set is used in the calculation of UFE in the Load aggregation process; and

(b) By Generation Resource (Resource ID (RID)), by Resource Entities, by QSE and Settlement Point: This data set is passed to the Settlement process for generation imbalance calculations.

11.5.2.1 Participant Specific Generation Data Posting/Availability

(1) The following market-specific generation information will be made available by ERCOT to each Market Participant:

(a) Generation unit production by Generation Resource Entity; and

(b) Generation unit production by QSE.

(2) Each Market Participant will have access only to its own information and/or the information of the Entities, which it represents. ERCOT will make the aforementioned data for each Settlement run available to Market Participants via the MIS Certified Area within 48 hours of finalizing the data for Settlement statements.

11.5.2.2 General Public Data Posting/Availability

(1) The following general market information will be posted to the MIS Secure Area:

(a) Total generation;

(b) Total Adjusted Meter Load (AML); and

(c) Total Wholesale Storage Load (WSL).

(2) ERCOT will make the aforementioned data for each Settlement run type available to Market Participants via the MIS Certified Area within 48 hours of finalizing the data for Settlement statements.

11.6 Unaccounted For Energy Analysis

11.6.1 Overview

(1) ERCOT will provide an annual Unaccounted For Energy (UFE) analysis report consisting of UFE data analysis from the preceding calendar year. This report will be based on final Settlement data and will be posted to the ERCOT website by April 30th. The appropriate Technical Advisory Committee (TAC) Subcommittee may:

(a) Request interim UFE analysis reports;

(b) Establish a task force for further UFE investigation that may include the establishment of UFE analysis zones. UFE analysis zones will not be used for Settlement purposes until adopted as UFE Settlement zones. Before adoption as UFE Settlement zones the following will be considered, at a minimum:

(i) Cost-benefit analysis;

(ii) Installation requirements for Revenue Quality Meters;

(iii) Impact on the Settlement system;

(iv) Impact on Market Participant systems; and

(v) Cost of UFE to Market Participants; and

(c) Identify factors that are contributing to UFE and work with the appropriate Entities to rectify problems causing UFE.

(2) ERCOT currently has one UFE zone for Settlement purposes, which encompasses all of ERCOT.

11.6.2 Annual Unaccounted For Energy Analysis Report

(1) The annual UFE analysis report will contain both ERCOT-wide and UFE allocation category quantities as follows:

(a) Total UFE MWhs;

(b) Total UFE cost;

(c) Percent of total UFE to ERCOT Load;

(d) Percent of total UFE cost; and

(e) Notice of any factors that may be contributing to UFE.

ERCOT Nodal Protocols

Section 12: Market Information System

June 1, 2022

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12 MARKET INFORMATION SYSTEM

12.1 Overview

(1) ERCOT shall create and maintain an electronic Market Information System ("ERCOT Market Information System" or "MIS"). The purpose of the MIS is to provide certain information available only to applicable Entities in the MIS Secure Area and to provide certain information available only to an individual Market Participant in the MIS Certified Area.

(2) The MIS Secure and Certified Areas provide restricted access to ERCOT Critical Energy Infrastructure Information (ECEII), to the extent that the Protocols or any Other Binding Document requires such information to be posted thereon. All ECEII posted on the MIS Secure or Certified Area shall be subject to the restrictions in Section 1.3.2, ERCOT Critical Energy Infrastructure Information. ECEII posted on the MIS Secure or Certified Area may be accessed only by those individuals that are issued ECEII-eligible Digital Certificates.

(3) ERCOT shall also create and maintain an Internet website with public and restricted areas.

12.2 ERCOT Responsibilities

(1) ERCOT shall post information to the Market Information System (MIS) as directed throughout these Protocols. With the exception of information requested by a Market Participant in accordance with paragraph (3) below, ERCOT may not use the MIS to post information beyond that specifically required in these Protocols or market guides as described in paragraph (2) of Section 1.1, Summary of the ERCOT Protocols Document.

(2) ERCOT may use the ERCOT website to communicate information that is not posted to the MIS.

(3) To the extent a request is reasonable, in ERCOT's sole discretion, ERCOT shall post to the MIS Certified Area information that is requested by a Market Participant but not required to be posted by these Protocols.

(4) ERCOT shall create and maintain a list of all of the posting requirements contained in these Protocols or market guides as described in paragraph (2) of Section 1.1. This list and changes thereto shall be posted to the ERCOT website.

(5) ERCOT shall post the list of Other Binding Documents to the ERCOT website.

(6) ERCOT shall use the MIS, as necessary, to post information that meets requirements to disseminate information under North American Electric Reliability Corporation (NERC) Reliability Standards. Information posted pursuant to this paragraph shall be added to the

list described in paragraph (4) above. ERCOT shall notify Market Participants via a Market Notice when such information is posted.

[NPRR244: Insert paragraph (7) below upon project completion:]

(7) ERCOT shall post to the ERCOT website business procedure documents, if they exist, for the following activities: credit management, process for conducting interconnection studies, process for conducting Reliability Must-Run (RMR) studies, processes for managing the commitment of RMR Units, process for conducting Reliability Unit Commitment (RUC) and Hourly Reliability Unit Commitment (HRUC), process for development of the Congestion Revenue Right (CRR) Auction models, process for determining the Pre-Assigned Congestion Revenue Right (PCRR) allocations, process for determining when a market price is to be revised, process for revising prices, and process for determining when units procured in DRUC or HRUC are not needed. For the above listed activities, ERCOT will post a business procedure document only after it has reviewed and determined that the document does not contain confidential information. If a business procedure document contains confidential information, such information shall be redacted before posting to the ERCOT website.

12.3 MIS Administrative and Design Requirements

(1) The Market Information System (MIS) must comply with the administrative and design requirements specified as follows:

(a) ERCOT shall ensure that all Market Participants have access to the ERCOT MIS on a nondiscriminatory basis.

(b) The MIS must, at a minimum, provide all information required under any regulations of the Public Utility Commission of Texas (PUCT) or other Governmental Authorities.

(c) The MIS must include any available information that may be used by a Qualified Scheduling Entity (QSE) to estimate or verify bills for all ERCOT-provided settlements.

(d) At the request of an Eligible Transmission Service Customer, ERCOT shall provide the methodology and data to independently reproduce information contained in the MIS related to the operation of the ERCOT market.

(e) The MIS must include security measures to safeguard ERCOT Critical Energy Infrastructure Information (ECEII) and protect the confidentiality of Protected Information as required by these Protocols.

(f) The MIS must comply with industry standards for commercial websites, including query and search functionality.

(g) The MIS must provide easy navigation based on the posting list described in paragraph (4) of Section 12.2, ERCOT Responsibilities, above for document retrieval. This navigability must include hyperlinks between listings and the MIS posted information.

12.4 ERCOT Website

(1) ERCOT shall create and maintain an Internet website consistent with industry standards for commercial websites, including query and search functionality. The Market Information System (MIS) or a link to the MIS must be available from the ERCOT website. ERCOT may use the ERCOT website to communicate information that is not posted to the MIS. Data, extracts, and reports required by the Protocols to be published on the ERCOT website must be made available on a non-discriminatory basis.

ERCOT Nodal Protocols

Section 13: Transmission and Distribution Losses

January 1, 2021

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13 TRANSMISSION AND DISTRIBUTION LOSSES

13.1 Overview

(1) This section sets forth the method for calculating Transmission and Distribution Losses (T&D Losses) and responsibilities of ERCOT, Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) with respect to T&D Losses.

13.1.1 Responsibility for Transmission and Distribution Losses

(1) T&D Losses are the responsibility of each QSE representing Load. ERCOT shall allocate T&D Losses to Load at the appropriate aggregate level as part of the data aggregation process to calculate the Load obligation of QSEs for settlement purposes.

(2) ERCOT shall forecast Transmission Loss Factors (TLFs) and post them to the ERCOT website by 0600 of the Day-Ahead period. ERCOT shall forecast the ERCOT-wide TLFs as a percentage of Load for each Settlement Interval of the Operating Day. By the close of business on the day following the Operating Day, ERCOT shall also calculate TLFs for each Settlement Interval using the actual system Load for that Settlement Interval and shall post the resulting deemed actual TLFs to the settlement system and the ERCOT website.

(3) ERCOT shall forecast Settlement Interval Distribution Loss Factors (DLFs) and post them to the ERCOT website by 0600 of the Day Ahead period. ERCOT shall forecast the Settlement Interval DLFs as a percentage of Load for each Settlement Interval of the Operating Day. On the day following the Operating Day, ERCOT shall also calculate Settlement Interval DLFs using actual system Load for that Settlement Interval and post the resulting deemed actual Settlement Interval DLFs to the settlement system and the ERCOT website.

(4) Distribution loss coefficients, and the calculation methodology from which they are derived, will be subject to audit by ERCOT for accurate and consistent application. Non-Opt-in Entities (NOIEs) with Interval Data Recorders (IDRs) at the settlement point of delivery are not required to provide Distribution loss coefficients and calculation methodology.

(5) In the special case where there are distribution facilities upstream from a wholesale NOIE or External Load Serving Entity (ELSE) settlement IDR, that settlement IDR will be compensated for line and transformer losses between the IDR and the ERCOT Transmission Grid to account for the Distribution Losses. The NOIE or ELSE will be then treated as a transmission level NOIE or ELSE. Calculations are subject to review by ERCOT. Since loss compensation is included in the wholesale settlement IDR, the TSP and/or DSP providing upstream wheeling facilities may need to offer wholesale wheeling tariffs excluding the losses that have already been compensated for.

13.1.2 Calculation of Losses for Settlement

(1) ERCOT shall use the deemed actual Settlement Interval DLFs applicable to each ESI ID and the deemed actual Settlement Interval TLFs when adjusting aggregated Load for losses to determine the QSE total Load obligations.

13.2 Transmission Losses

13.2.1 Forecasted Transmission Loss Factors

(1) The forecasted Transmission Loss Factor (TLF) for each interval in the Operating Day shall be a linear interpolation or extrapolation using the on-peak and the off-peak TLFs and the corresponding forecast of ERCOT System Load during the same interval to calculate the loss factors.

(2) At 0600 of the Day-Ahead period, ERCOT shall forecast a TLF for each Settlement Interval of the Operating Day and post on the ERCOT website the forecasted TLFs which correspond to the Operating Day forecast. The source of the on-peak and off-peak losses are the ERCOT load flow base cases for the applicable season. For the purpose of Section 13.2, Transmission Losses, “season” is defined as those set forth in item (1) of Section 13.2.4, Seasonal Transmission Loss Factor Calculation.

13.2.2 Deemed Actual Transmission Loss Factors

(1) ERCOT shall determine the deemed actual TLF for each interval in the Operating Day, by use of a linear interpolation or extrapolation using the on-peak and the off-peak TLFs corresponding to the actual ERCOT System Load during the interval.

(2) The day after the Operating Day, ERCOT shall calculate deemed actual TLFs for each Settlement Interval of the Operating Day and publish the TLFs to be used in Settlement calculations.

(3) ERCOT shall use the TLFs corresponding to the on-peak and off-peak base case ERCOT System Loads during the applicable seasons as the basis for the ERCOT-wide deemed actual TLFs. ERCOT will post TLFs to the ERCOT website by 0600 two days after the Operating Day.

13.2.3 Transmission Loss Factor Calculations

(1) The following formulas shall be used to translate the seasonal on-peak and off-peak TLFs into Settlement Interval TLFs.

$$\text{TLF}_i = (\text{SSC} * \text{SIEL}_i) + \text{SIC}$$

Variable	Unit	Description
i	none	Interval
TLF_i	none	Transmission Loss Factor for a Settlement Interval
$SIEL_i$	MWh	Settlement Interval ERCOT System Load (forecasted or actual)
SSC	none	Seasonal Slope Coefficient
SIC	none	Seasonal Intercept Coefficient

And

SSC = (SONLF – SOFFLF)/(SONL-SOFFL)

SIC = [(SOFFLF*SONL)-(SONLF*SOFFL)]/(SONL-SOFFL)

Variable	Unit	Description
SONLF	none	Seasonal on-peak percent loss factor
SOFFLF	none	Seasonal off-peak percent loss factor
SONL	none	Seasonal on-peak Load value
SOFFL	none	Seasonal off-peak Load value

13.2.4 Seasonal Transmission Loss Factor Calculation

(1) Seasonal on-peak and off-peak TLFs are derived from the annually updated ERCOT on-peak and off-peak load flow base cases analysis by ERCOT. Base cases reflect the most current data on the transmission system and Generation Resource Dispatch. The ERCOT Transmission Grid topology and related Generation Resource Dispatch in the base cases are the critical factors in calculating losses. Seasonal time periods are defined as follows:

(a) Spring (March – May)

(b) Summer (June – September)

(c) Fall (October – November)

(d) Winter (December – February)

(2) ERCOT shall calculate seasonal TLFs by dividing ERCOT seasonal case Transmission Losses (60 kV system and higher) by the ERCOT seasonal base Load adjusted (reduced) for self-serve Load modeled in the case. The resulting TLFs are expressed as a percentage of Load.

(3) ERCOT shall post the seasonal TLFs to the ERCOT website prior to the start of the year for the next four seasons beginning with the Spring season.

13.2.5 Loss Monitoring

(1) ERCOT shall monitor Transmission Losses annually and will investigate any abnormal loss factors. ERCOT and TSPs shall use the cost of losses as one criterion in evaluating the need for transmission additions.

13.3 Distribution Losses

(1) By October 30th of each year for the next calendar year, or two months prior to the posting of any update to the approved Distribution loss coefficients, codes, or calculation, each Distribution Service Provider (DSP), except Non-Opt-In Entities (NOIEs), shall calculate and provide ERCOT the annual Distribution loss coefficients to be applied to distribution voltage level Loads in its area of certification. ERCOT shall review and approve the Distribution Loss Factor (DLF) calculation methodology used by each DSP prior to use of the loss coefficients for settlement purposes. If the DLF calculation methodology does not conform with ERCOT's interpretation of the Protocol criteria in this subsection, ERCOT will work with the DSP to correct the deficiency. Until deficiencies are resolved, the last approved Distribution loss coefficients and the calculation methodology will be posted, and the last approved Distribution loss coefficients shall be used for settlement. A DSP may only submit a change to the DLF calculation methodology annually or when a change in a DSP service area warrants an update to the approved DLF methodology based on the DSP internal evaluation.

(2) The DSP shall assign a Distribution loss code to each Electric Service Identifier (ESI ID). A maximum of five Distribution loss codes may be submitted for each DSP based upon ERCOT approved parameters, such as service voltages or number of transformations.

(3) The following standards will be used to identify the Distribution loss code applicable to each ESI ID:

- T = Transmission connected Customers (no Settlement Interval DLF applied)
- A through E = Transmission and/or Distribution Service Provider (TDSP) defined Customer segment(s)

(4) The DSPs, except NOIEs, are obligated to provide Distribution loss coefficients to ERCOT. ERCOT will post the Distribution loss coefficients and calculation methodology, for each DSP.

(5) Distribution loss information submitted by the DSP shall include:

(a) The annual Distribution loss coefficients (F_1, F_2, and F_3) for each Distribution loss code; and

(b) The methodology upon which the calculation of the coefficients (F_1, F_2, and F_3) was made.

(6) A NOIE may provide ERCOT with the information detailed in paragraph (5) above. If such information is provided, ERCOT shall calculate and post NOIE DSP DLFs using the same processes for the calculation and posting of competitive DSP DLFs.

13.3.1 Loss Factor Calculation

(1) ERCOT shall use the Distribution loss coefficients submitted by the DSP to calculate the Settlement Interval DLFs. Settlement Interval DLFs will be calculated from the data provided by DSPs as follows using the following equation:

$$SILF_i = F_1 * (SIEL_i/AAL) + F_2 + F_3 / (SIEL_i/AAL)$$

Variable	**Unit**	**Description**
i		interval
SILFi		Settlement Interval DLF
SIELi		Settlement Interval ERCOT System Load (forecasted or actual)
AAL		Annual Interval Average ERCOT System Load. The AAL is calculated using the total ERCOT Load stated in the most recent settlement during the period beginning on September 1 and ending August 31. ERCOT will provide the AAL to DSPs that are obligated to provide Distribution loss coefficients and calculation methodology to ERCOT, by September 15th of each year.
F_1, F_2, F_3		Distribution Loss coefficients determined by the Distribution Service Provider to allow calculation of its SILF from ERCOT System Load

(2) ERCOT shall use the deemed actual Settlement Interval DLFs calculated for each Settlement Interval of the Operating Day for settlement purposes.

13.3.2 Loss Monitoring

(1) Distribution loss coefficients and the calculation methodology from which they are derived for all DSPs, except for NOIEs, will be submitted to ERCOT and will be subject to audit for accuracy and consistency of application.

13.4 Special Loss Calculations for Settlement and Analysis

13.4.1 Deemed Actual Transmission Losses for NOIEs

(1) All Qualified Scheduling Entities (QSEs) representing Load, including Non-Opt-In Entities (NOIEs), will be responsible for Transmission Losses allocated in the manner described in these Protocols. Those Entities using transmission tie line meters to determine Load will adjust the net meter readings to remove calculated Transmission Losses behind the meter in order to determine the Load responsibility of the Entity.

ERCOT will provide to Settlement the calculation of the losses behind the meters, for each interval, using actual system conditions for that interval.

(2) The deemed actual Transmission Losses for NOIEs shall be a linear interpolation or extrapolation between the seasonal on-peak and the seasonal off-peak NOIE Transmission Loss Factors (TLFs) posted pursuant to paragraph (3) of Section 13.2.4, Seasonal Transmission Loss Factor Calculation, corresponding to the actual NOIE metered Load in the interval.

ERCOT Nodal Protocols

Section 14: State of Texas Renewable Energy Credit Trading Program

January 1, 2021

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14 STATE OF TEXAS RENEWABLE ENERGY CREDIT TRADING PROGRAM

14.1 Overview

(1) On May 9, 2000, the Public Utility Commission of Texas (PUCT) appointed ERCOT as Program Administrator of the Renewable Energy Credits (REC) Trading Program described in subsection (g) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

(2) The purposes of the REC Trading Program are:

- (a) To ensure that the cumulative installed generating capacity from renewable energy technologies in this state totals 2,280 megawatts (MW) by January 1, 2007, 3,272 MW by January 1, 2009, 4,264 MW by January 1, 2011, 5,256 MW by January 1, 2013, and 5,880 MW by January 1, 2015, with a target of at least 500 MW of the total installed renewable capacity after September 1, 2005, coming from a renewable energy technology other than a source using wind energy, and that the means exist for the state to achieve a target of 10,000 MW of installed renewable capacity by January 1, 2025;

- (b) To provide for a REC Trading Program by which the renewable energy requirements established by the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.904(a) (Vernon 1998 & Supp. 2007) (PURA) may be achieved in the most efficient and economical manner; to encourage the development, construction, and operation of new renewable energy Resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial Resources; to protect and enhance the quality of the environment in Texas through increased use of renewable Resources; and

- (c) To ensure that all Customers have access to providers of energy generated by renewable energy Resources pursuant to PURA § 39.101(b)(3).

(3) ERCOT shall administer the REC Trading Program, which became effective July 1, 2001. Entities participating in the REC Trading Program must register with and execute the appropriate agreements with ERCOT.

14.2 Duties of ERCOT

(1) As described in more detail in this Section, ERCOT shall:

- (a) Register renewable energy generators;

- (b) Register offset generators;

- (c) Register Retail Entities;

(d) Register other Entities choosing to participate in the Renewable Energy Credit (REC) Trading Program;

(e) Create and maintain REC trading accounts for REC Trading Program participants;

(f) Determine the annual Renewable Portfolio Standard (RPS) requirement for each Retail Entity in Texas using the formulas set forth in this Section;

(g) On a quarterly basis, award RECs or Compliance Premiums earned by REC generators based on verified MWh production data;

(h) Verify that Retail Entities meet annual REC compliance requirements;

(i) Retire RECs or Compliance Premiums as directed by REC Trading Program participants;

(j) Retire RECs or Compliance Premiums as they expire;

(k) On a monthly basis, make public the aggregated total MWh competitive energy sales in Texas;

(l) Make public a list of REC Account Holders with contact information (e-mail, address, and telephone number) so as to facilitate REC or Compliance Premium trading;

(m) Maintain a list of offset generators and the Retail Entities to whom such a generator's offsets were awarded by the Public Utility Commission of Texas (PUCT);

(n) Conduct a REC Trading Program Settlement process annually;

(o) File an annual report with the PUCT as specified in subsection (g)(11) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy;

(p) Monitor the operational status of participating renewable energy generation facilities in Texas and record retirements;

(q) Compute and apply a revised Capacity Conversion Factor (CCF) (as described in Section 14.9.2, Capacity Conversion Factor) every two years;

(r) Audit MWh production data from certified REC generating facilities;

(s) Audit MWh production from renewable energy generation facilities producing offsets for Retail Entities on an annual basis;

(t) Post a list of Facility Identification Numbers, and the associated renewable energy generation facility name, location, type, and noncompetitive certification data on the ERCOT website; and

(u) Receive, implement and protect the confidentiality of Electric Service Identifiers (ESI IDs), identity of Retail Electric Provider (REP), and consumption data associated with transmission-level Customers that choose to have their Load excluded from the RPS calculation consistent with Section 14.5.3, End-Use Customers, and subsection (j) of P.U.C. SUBST. R. 25.173.

14.2.1 Site Visits

(1) ERCOT may conduct site visits to renewable energy generation facilities on a random basis to ensure integrity of the REC Trading Program, as deemed necessary. ERCOT shall require each registered renewable energy generator to provide one or more contact persons for purpose of site visit notification. ERCOT shall provide at least 48 hours' notice to the designated contact(s) prior to conducting a site visit for Intermittent Renewable Resources (IRRs) only.

14.3 Creation of Renewable Energy Credit Accounts and Attributes of Renewable Energy Credits

14.3.1 Creation of Renewable Energy Credit Accounts

(1) ERCOT shall create Renewable Energy Credit (REC) Accounts for any party desiring to participate in the REC Trading Program. ERCOT shall require all holders of REC Accounts to execute a Standard Form Market Participant Agreement (as provided for in Section 22, Attachment A, Standard Form Market Participant Agreement) with ERCOT. Each party requesting a REC Account must name a Designated Representative. The Designated Representative must have the authority to represent and legally bind the REC Account Holder in all matters pertaining to the REC Trading Program. These individuals will be the contact persons for ERCOT on matters regarding a REC Account.

14.3.2 Attributes of Renewable Energy Credits and Compliance Premiums

(1) A REC or Compliance Premium is a tradable instrument that represents all of the renewable attributes associated with one MWh of production from a certified renewable generator. A REC or Compliance Premium may trade separately from energy. RECs are distributed to REC generators on a quarterly basis by ERCOT. The number of RECs distributed to a certified generator is based on physically metered MWh production. RECs may be traded, transferred, and retired.

(2) Compliance Premiums are awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy Resource that is not powered by wind and meets the criteria of subsection (l) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. For the purpose of the Renewable Portfolio Standard (RPS) requirements, one Compliance Premium is equal to one REC.

(3) The components of a REC and Compliance Premium are defined in the table below.

REC Information	Field Length	Description
Year	4 Digits	Year REC was issued.
Quarter	1 Digit	Quarter REC was issued.
Type of Renewable Resource	20 Characters	Reference to type of renewable Resource: Solar, wind, biomass, tidal, geothermal, hydro, landfill gas, other.
Facility Identification Number	5 Digits	Number to be assigned by ERCOT.
REC Number	8 Digits	REC Number 1 through the number of MWh generated by the facility during the quarter.

(4) The Facility Identification Number assigned by ERCOT will be fixed for a facility's lifetime, and will therefore remain constant regardless of changes in facility name or ownership. Facilities must file changes of name, ownership, or other relevant certification information with ERCOT within 30 days of such changes.

(5) Generating facilities that lose their Public Utility Commission of Texas (PUCT) REC generator certification will not be awarded RECs by ERCOT subsequent to the date of the certification revocation, unless ERCOT is otherwise directed by the PUCT.

(6) A REC or Compliance Premium will have an issue date of the Compliance Period in which it is generated.

(7) RECs and Compliance Premiums have a useful life of three Compliance Periods. For example, a qualifying MWh of renewable energy generated on December 31, 2006 will be the basis for a REC having an issue date of 2006. The three Compliance Periods for which this REC may be used are 2006, 2007, and 2008. This REC will expire one Business Day after March 31, 2009. March 31 is the date by which a Retail Entity must submit its annual REC compliance retirement information to ERCOT.

14.4 Registration to Become a Renewable Energy Credit Generator or Renewable Energy Credit Aggregator

(1) Renewable Energy Credit (REC) generators or REC aggregators must apply to the Public Utility Commission of Texas (PUCT) for certification to produce or aggregate RECs. On receipt of a copy of a notification from the PUCT certifying that a renewable energy generation facility is eligible to generate or an Entity is eligible to aggregate RECs, ERCOT shall establish a REC trading account for the facility or Entity. Each REC trading account shall have a unique identification number.

(2) ERCOT may close an account holding no RECs or Compliance Premiums for a period of one year after providing 30 days' advance Notice to the REC Account Holder.

14.5 Reporting Requirements

14.5.1 Renewable Energy Credit Generators and Renewable Energy Credit Offset Generators

(1) All Renewable Energy Credit (REC) generators and REC offset generators must report quarterly MWh production data to ERCOT no later than the 38th day after the last Operating Day of the quarter, in an electronic format prescribed by ERCOT. The reported MWh quantity shall be solely produced from, and attributable to, a renewable generator as so designated by the Public Utility Commission of Texas (PUCT). Information relevant to quarterly reporting shall be handled in one of the following processes:

(a) A renewable Generation Resource or Settlement Only Generator (SOG) that has interval meters, pursuant to Section 10, Metering, and has interval metered generation data provided to ERCOT for energy Settlement will:

(i) Have the quarterly reporting function performed on their behalf by ERCOT using the Settlement Quality Meter Data extracted from the ERCOT Settlement system; or

(ii) Self-report their Settlement quality MWh production data to ERCOT, in a format and on a timeline prescribed by ERCOT, based on Metering Facilities that are:

(A) Installed, operated and maintained by the REC generator;

(B) Installed in a location to only record energy from generation certified by the PUCT to receive RECs;

(C) Compliant with American National Standards Institute (ANSI) C12, Code for Electricity Metering, metering accuracy standards; and

(D) Verified for accuracy every six years.

(b) REC aggregators shall report production from microgenerator renewable energy Resources that are not interval metered for energy Settlement, in accordance with the methodology approved by the PUCT for the purposes of measuring the REC production of such Resources, in the format prescribed by ERCOT, including applicable supporting documentation;

(c) All other REC generators, not specifically covered in items (a) and (b) above, must report Settlement quality MWh production data to ERCOT in a format and on a timeline prescribed by ERCOT; provided that REC generators not interconnected to any Transmission and/or Distribution Service Provider (TDSP) may use performance measures for REC production as approved by the PUCT; or

(d) Entities certified to produce RECs from landfill gas supplied directly to a gas distribution system operated by a Municipally Owned Utility (MOU) shall report the MWh equivalent production data and supporting calculations to ERCOT on a timeline prescribed by ERCOT.

(2) From time to time, or as determined to be necessary by ERCOT or the PUCT, Entities may be required to submit supporting documentation to allow verification of generation quantities.

(3) The failure of a REC generator to report generation data in a timely fashion shall result in a delay in the issuance of RECs or Compliance Premiums for that generation facility for that quarter. RECs or Compliance Premiums delayed by untimely reporting will be awarded during the REC award period next occurring after the required data are reported. The issue date of such RECs or Compliance Premiums will be based on the quarter in which the RECs or Compliance Premiums were actually generated.

14.5.2 Retail Entities

(1) To enable Retail Entities the ability to calculate their Renewable Portfolio Standard (RPS) requirements, all Retail Entities serving Load in the state of Texas shall provide Load data to ERCOT on a monthly basis, and no later than the 38th day after the last Operating Day of the month, in an electronic format prescribed by ERCOT. The reported MWh quantity shall be solely the energy consumed by Customers in Texas. Load data shall be provided in one of the following processes:

(a) Retail Entities serving Load located within ERCOT shall have this function performed for them by ERCOT for the Load served within ERCOT. The data supplied by ERCOT shall be Settlement Quality Meter Data extracted from the ERCOT Settlement system; or

(b) Entities participating in the REC Trading Program that serve Load outside the ERCOT Region must report Settlement quality MWh Load data for Load served outside the ERCOT Region to ERCOT in a format prescribed by ERCOT.

(i) Entities reporting under paragraph (b) shall not include any MWhs served to a location for which a Customer has submitted a notice letter pursuant to subsection (j) of P.U.C. SUBST. R 25.173, Goal for Renewable Energy.

(ii) Notwithstanding the foregoing reporting requirements, such Entities shall submit monthly MWh Load data for December of each year by no later than January 15 of the following year. Any error in estimating December

Load shall be corrected by the submitting Entity in the following year's true-up calculation as per subsection (h)(3) of P.U.C. SUBST. R. 25.173.

(2) On a monthly basis, ERCOT shall calculate the MWh consumption of energy by Customers served by Retail Entities in Texas, using Load data submitted by program participants. ERCOT shall adjust the Load data to ensure that any Load (MWh) covered by notice consistent with Section 14.5.3, End-Use Customers, is removed.

(3) The failure of a Retail Entity to report required Load data (including Load data for Electric Service Identifiers (ESI IDs) or accounts covered by notice, as specified in Section 14.5.3) in accordance with the Protocols shall result in estimation of Load data for the applicable Retail Entity by ERCOT for purposes of allocation of annual RPS requirements.

14.5.3 End-Use Customers

(1) To enable ERCOT to determine the total retail sales of all Retail Entities and the retail sales of a specific Retail Entity for Section 14.9.3.1, Preliminary Renewable Portfolio Standard Requirement for Retail Entities, and Section 14.9.5, Final Renewable Portfolio Standard Requirement, a transmission-level voltage Customer that wishes to have its Load excluded from RPS calculations pursuant to subsection (j) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, must submit the information in accordance with the rule.

14.6 Awarding of Renewable Energy Credits

(1) Following the end of each calendar quarter, and before the end of the next Business Day following receipt of all Renewable Energy Credit (REC) generator and Load data specified in Section 14.5.1, Renewable Energy Credit Generators and Renewable Energy Credit Offset Generators, and in Section 14.5.2, Retail Entities, ERCOT will credit RECs to the appropriate REC trading account. ERCOT shall base the number of RECs to be issued on the MWh generation data provided by REC generators or ERCOT as applicable. The number of RECs issued to a specific REC generator will be equal to the number of MWh generated by the certified generator during the quarter. Quarterly production shall be rounded to the nearest whole MWh, with fractions of 0.5 MWh or greater rounded up. If a REC generator is decertified during the quarter, RECs will be issued on MWhs produced during the quarter until the date and time of decertification.

14.6.1 Adjustments to Renewable Energy Credit Award Calculations

(1) Adjustments (reductions) to REC awards are made for renewable facilities that use more than 2% fossil fuel, renewable facilities that are repowered, and for REC aggregators that use estimation techniques to report generation.

(a) Co-Fired Generator Adjustments:

(i) For REC generators using a renewable energy technology that requires the use of fossil fuel that is greater than 2%, and less than or equal to 25%, of the total annual fuel input on a British Thermal Unit (BTU) or equivalent basis, RECs can only be earned on the renewable portion of the production. RECs are awarded based on an adjusted number of MWh generated during the quarter.

(ii) The renewable energy Resource shall calculate the electricity generated by the unit in MWh, based on the BTUs (or equivalent) produced by the fossil fuel and the efficiency of the renewable energy Resource, subtract the MWh generated with fossil fuel input from the total MWh of generation and report the renewable energy generated to the Program Administrator;

(b) Repowered Facility Adjustments:

(i) A Repowered Facility is eligible to earn RECs on all renewable energy produced up to a capacity of 150 MW. Capacity greater than 150 MW may earn RECs for the energy produced in proportion to 150 divided by nameplate capacity.

(ii) Repowered Facilities with a generation capacity greater than 150 MW will be awarded RECs based on an adjusted number of MWh generated during the quarter.

$$\textbf{AdjustedMWh} = \textbf{HO}_{q}\ \textbf{(150 / NC)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
HO_q	MWh	Total production or historical output by the Repowered Facility for quarter “q”
NC	None	Nameplate capacity is the machine generation capacity posted on a specific piece of equipment or unit

(c) REC Aggregator Adjustments:

The REC aggregator may provide the Program Administrator with sufficient information for the Program Administrator to estimate with reasonable accuracy the output of each unit, based on known or observed information that correlates closely with the generation output. REC aggregators using approved estimation techniques to report renewable energy production shall be awarded one REC for every 1.25 MWh generated.

14.6.2 Awarding of Compliance Premiums

(1) A Compliance Premium is awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy Resource installed and certified after September 1, 2005 that is not powered by wind. For the purpose of the Renewable Portfolio Standard (RPS) requirements, one Compliance Premium is equal to one REC.

(2) One Compliance Premium shall be awarded for each REC awarded for energy generated after December 31, 2007.

14.7 Transfer of Renewable Energy Credits or Compliance Premiums Between Parties

(1) On the receipt of a request from the owner of a Renewable Energy Credit (REC) or Compliance Premium and purchaser of the REC or Compliance Premium, ERCOT will transfer the REC or Compliance Premium from the owner’s REC trading account to the REC trading account specified in the transfer request. Transfer requests received by ERCOT shall be effective upon confirmation by the receiving Entity.

(2) If a request for transfer cannot be executed, ERCOT will notify the requesting Entities of the reason.

(3) On completing a transfer, ERCOT shall notify the Designated Representatives of all involved REC trading account owners by e-mail.

(4) For the purpose of the REC Trading Program, RECs or Compliance Premiums residing in an Entity’s REC trading account are deemed to be owned by that Entity.

(5) To the extent practicable, ERCOT will accommodate automated quarterly transfers.

14.8 Renewable Energy Credit Offsets

(1) To qualify for Renewable Energy Credit (REC) offsets in the REC Trading Program, a Retail Electric Provider (REP), Municipally Owned Utility (MOU), generation and transmission cooperative, distribution cooperative, or an affiliate of a REP, MOU, generation and transmission cooperative, or distribution cooperative must apply for REC offsets from the Public Utility Commission of Texas (PUCT) by June 1, 2001. This requirement is in effect without regard to whether or not the applicant will be a Retail Entity on January 1, 2002. A REC offset represents one MWh of renewable energy from a renewable energy generator placed in service before September 1, 1999 that may be used in place of a REC to meet a renewable energy requirement. REC offsets may not be traded.

(2) After receipt of Notification from the PUCT (which shall include the name of the Entity receiving the offset, the name of the generator eligible to produce the offset, the value of the offset in MWh, and other information as applicable) verifying designation by the Entity receiving REC offsets, ERCOT shall use REC offsets from a Retail Entity as part

of its calculation of Final RPS Requirements (FRRs). REC offsets are not transferable. REC offsets will be considered valid until ERCOT receives Notification from the PUCT that the offset is no longer valid.

(3) For purposes of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, a generation and transmission cooperative shall be responsible for the cumulative total of its cooperative members' renewable energy requirements as well as its affiliated cooperative members' renewable energy requirements. At the election of its board of directors, a generation and transmission cooperative will become responsible for the cumulative total of its distribution cooperatives' Renewable Portfolio Standard (RPS) requirements. The sharing of the REC offsets of the generation and transmission cooperative among its distribution cooperatives shall not affect the cumulative total of the RPS requirements of the distribution cooperative members, or its affiliated cooperative members in meeting their share of the state's goals for renewable energy Resources.

14.9 Allocation of Statewide Renewable Portfolio Standard Requirement Among Retail Entities

(1) The first quarter of each year shall be the Settlement period for the preceding Compliance Period. During this Settlement period each year the following actions shall occur:

(a) No later than the date set forth in P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, the Program Administrator shall allocate the Statewide RPS Requirement (SRR) for the previous year's Compliance Period among all Retail Entities in the state. This allocation represents the Renewable Energy Credit (REC) compliance requirements for the preceding Compliance Period. To perform this calculation, ERCOT shall use Load data provided to it as set forth in these Protocols.

(b) By the date set forth in P.U.C. SUBST. R. 25.173, the Program Administrator shall notify each Retail Entity of its Final RPS Requirement (FRR) for the previous Compliance Period.

(c) The Program Administrator may request from the Public Utility Commission of Texas (PUCT) an adjustment to the deadlines set forth in this Section if certain factors, including but not limited to changes to the ERCOT Settlement Calendar, should affect the timely availability of reliable retail sales data or renewable Resource generation data necessary for calculating Renewable Portfolio Standard (RPS) requirements.

14.9.1 Annual Capacity Targets

(1) The renewable energy capacity targets (in megawatts) for each year are as follows:

Annual Capacity Target (MW)	Existing Renewable Capacity (MW)	Total Renewable	Compliance Period (Years)

		Capacity Target (MW)	
400	880	1280	2002, 2003
850	880	1730	2004, 2005
1400	880	2280	2006, 2007
2392	880	3272	2008, 2009
3384	880	4264	2010, 2011
4376	880	5256	2012, 2013
5000	880	5880	2014, and each year after 2014

(2) ERCOT shall increase the new renewable energy capacity target for all future Compliance Periods to account for:

(a) Capacity producing RECs from eligible qualifying out-of-state facilities metered in Texas; and

(b) Capacity from a renewable energy generator placed in service before September 1, 1999 that has been retired or otherwise removed from the program and results in a statewide existing renewable capacity of less than 880 MW.

ERCOT shall apply any such changes for out-of-state capacity and retirements at such time the revised Capacity Conversion Factor (CCF) is computed and applied.

(3) RECs may be produced by generators certified by the PUCT which are not located in Texas if:

(a) The first metering point for such generation is in Texas; and

(b) All generation metered at the location of injection into the Texas grid comes from that generator.

(4) REC generators physically located outside the state of Texas are not included in the annual calculations of installed renewable capacity for purposes of the REC Trading Program. However, as such generation may contribute to the available pool of RECs, it is conceivable that there may be sufficient RECs to allow Retail Entities to meet their annual requirements, while at the same time, a target capacity shortfall for installed renewable capacity in Texas could exist.

14.9.2 Capacity Conversion Factor

(1) ERCOT shall set the CCF to allocate credits to Retail Entities. The CCF shall be calculated during the fourth quarter of each odd numbered compliance year. ERCOT shall determine a new CCF as follows:

$$\textbf{Individual Facility CCF}_{i} = (12/n)* \sum_{t=1}^{n} \textbf{HO}_{i,t} / (\textbf{HC}_{i,t} * 8760)$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	Individual renewable energy generation facility
n	None	Number of months a specific renewable energy generation facility was in operation over the past 24 months. n must be greater than or equal to 12 and less than or equal to 24.
$\text{HO}_{i,t}$	MWh	Total production by participating renewable generator i during Compliance Period t.
$\text{HC}_{i,t}$	MW	Average total generation capacity by participating renewable generator i during Compliance Period t.

and

$$\textbf{CCF} = \sum_{i-1}^{q} (\textbf{CCF}_{i} * \textbf{PC}_{i}) / \sum_{i-1}^{q} \textbf{PC}_{i}$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	The total number of renewable energy generation facilities in the REC Trading Program
PC_{i}	MW	Participating Capacity as of September 30 of the year the revised CCF is calculated for renewable energy generation facility i in the state of Texas participating in the REC Trading Program for which at least 12 months of operating data are available.

(2) The CCF shall:

(a) Be based on actual generator performance data for the previous two years for all renewable Resources in the REC Trading Program during that period for which at least 12 months of performance data are available;

(b) Represent a weighted average of generator performance; and

(c) Use all actual generator performance data that are available for each renewable Resource, excluding data for testing periods.

(3) For purposes of calculating historical output from renewable capacity, ERCOT shall keep a list of renewable generators, REC certification dates, and annual MWh generation totals.

(4) ERCOT shall use this revised CCF for the two Compliance Periods immediately after it is set. If the PUCT has determined that the REC Trading Program is failing to meet the statutory targets for renewable energy capacity in Texas, it will instruct ERCOT to use a different number than that which would be calculated using the formula for the CCF. Such requests will be published on the ERCOT website within ten Business Days of receipt of the letter from the PUCT.

14.9.3 Statewide Renewable Portfolio Standard Requirement

(1) ERCOT shall determine the SRR for a particular Compliance Period as follows:

$$\mathbf{SRR = (ACT * 8760 * CCF) + RCP}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
ACT	MW	Annual Capacity Target for new renewable energy generation facilities.
8760	None	The number of hours in a year.
CCF	None	Capacity Conversion Factor.
RCP	None	The number of Compliance Premiums retired during the previous Compliance Period.

14.9.3.1 Preliminary Renewable Portfolio Standard Requirement for Retail Entities

(1) ERCOT shall determine each Retail Entity’s Preliminary RPS Requirement as follows:

$$\mathbf{Preliminary\ RPS\ Requirement}_{i} = \mathbf{SRR * (CRSRES}_{i}\mathbf{ / TS)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
i	None	Specific Retail Entity.
SRR	REC	Statewide RPS requirement.
CRSRES_{i}	MWh	Retail sales of the specific Retail Entity to Texas Customers during the Compliance Period, excluding sales by the specific Retail Entity to any Electric Service Identifiers (ESI IDs) or accounts for which an opt-out notice has been submitted under subsection (j) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.
TS	MWh	Total retail sales of all Retail Entities to Texas Customers during the Compliance Period, excluding all sales of all Retail Entities to ESI IDs or accounts for which an opt-out notice has been submitted under subsection (j) of P.U.C. SUBST. R. 25.173.

(2) The sum of the Preliminary RPS Requirements for all Retail Entities shall be equal to the SRR.

14.9.4 Application of Offsets - Adjusted Renewable Portfolio Standard Requirement

(1) For a Retail Entity that has been awarded offsets by the PUCT, ERCOT shall subtract the REC offset amount from the Preliminary RPS Requirement. The reduction shall not exceed what would be necessary for the Final RPS Requirement to be zero. The total MWh reduction in the Preliminary RPS Requirement for all Retail Entities constitutes Total Useable Offsets (TUOs).

(2) ERCOT shall determine each Retail Entity's Adjusted RPS Requirement (ARR) as follows:

$$\textbf{ARR}_{i} = \textbf{Preliminary RPS Requirement}_{i} - \textbf{EO}_{i}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
i	None	Specific Retail Entity.
EO_i	None	Total offsets the Retail Entity is entitled to receive during the Compliance Period (not to exceed the Retail Entity's FRR before adjustment for any previous Compliance Period).

(3) ERCOT shall determine TUOs as follows:

$$\textbf{TUO} = \textbf{SRR} - \sum_{i=1}^{n} \textbf{ARR}_{i}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
i	None	Specific Retail Entity.
n	None	Number of Retail Entities.
SRR	None	Statewide RPS Requirement.
ARR_i	None	Adjusted RPS Requirement for a specific Retail Entity.

14.9.5 Final Renewable Portfolio Standard Requirement

(1) ERCOT shall redistribute the TUO amount over all Retail Entities to determine the FRRs. ERCOT shall determine each Retail Entity's FRR as follows:

FRR = ARR $_i$ + (TUO × (CRSRES $_i$ / TS)) +/- Previous Year(s) FRR adjustment (recalculated in accordance with subsection (h)(3) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy)

The above variables are defined as follows:

Variable	**Unit**	**Description**
ARR $_i$	None	Adjusted RPS Requirement for a specific Retail Entity.
TUO	None	Total Usable Offsets.
CRSRES $_i$	MWh	Retail sales of the Retail Entity to Texas Customers during the Compliance Period, excluding sales by the specific Retail Entity to any ESI IDs or accounts for which an opt-out notice has been submitted under subsection (j) of P.U.C. SUBST. R. 25.173.
TS	MWh	Total retail sales of all Retail Entities to Texas Customers during the Compliance Period, excluding all sales or accounts of all Retail Entities to ESI IDs for which an opt-out notice has been submitted under subsection (j) of P.U.C. SUBST. R. 25.173.

(2) This process will be an iterative process that will solve until the optimal allocation is reached with all FRRs resolved to the nearest whole REC.

(3) ERCOT shall notify each Retail Entity of its FRR for the previous Compliance Period no later than the date set forth for such Notification in subsection (n)(l) of P.U.C. SUBST. R. 25.173.

14.10 Retiring of Renewable Energy Credits or Compliance Premiums

(1) A Renewable Energy Credit (REC) or Compliance Premium owner's Designated Representative must submit retirement requests to ERCOT. RECs or Compliance Premiums specified by a Designated Representative for retirement must be in the REC trading account from which they are being retired at the time the request is submitted. ERCOT shall retire such RECs or Compliance Premiums by removing them from the party's REC trading account and retiring the unique serial number, thus rendering the REC or Compliance Premium unusable for any other purpose. ERCOT shall maintain records to archive all RECs or Compliance Premiums that have been retired and to identify the basis on which RECs or Compliance Premiums were retired. The reasons for retiring RECs include mandatory compliance, voluntary retirement, and expiration. The reasons for retiring Compliance Premiums include mandatory compliance, voluntary retirement, and expiration.

14.10.1 Mandatory Retirement

(1) For each Compliance Period, by the date set forth in subsection (n)(2) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, each Retail Entity's Designated Representative shall notify ERCOT of the RECs or Compliance Premiums in its REC trading account to be used (retired) to satisfy its Final RPS Requirement (FRR) for the Compliance Period being settled. Each REC or Compliance Premium that is not used will remain in the holder's REC trading account until it is transferred to another party's account, expires, or is otherwise retired.

(2) Failure to provide sufficient RECs or Compliance Premiums by the date set forth in subsection (n)(2) of P.U.C. SUBST. R. 25.173 shall be considered a failure of that Retail Entity to meet its REC retirement obligations. ERCOT shall notify the Public Utility Commission of Texas (PUCT) when any Retail Entity fails to meets its REC retirement obligations.

14.10.2 Voluntary Retirement

(1) At the request of a REC Account Holder, ERCOT shall retire RECs and Compliance Premiums for reasons other than for meeting the mandated Renewable Portfolio Standard (RPS) requirements. Voluntarily retired RECs and Compliance Premiums may not be used to satisfy a Retail Entity's RPS requirement. ERCOT shall include information concerning RECs and Compliance Premiums retired voluntarily in its annual report to the PUCT.

14.10.3 Retiring Unused Renewable Energy Credits or Compliance Premiums

(1) ERCOT shall retire all unused RECs and Compliance Premiums upon their expiration as described in Section 14.3.2, Attributes of Renewable Energy Credits and Compliance Premiums.

14.11 Penalties and Enforcement

(1) ERCOT is not responsible for developing, administering, or enforcing penalties associated with the Renewable Energy Credit (REC) Trading Program; these activities are within the scope of the Public Utility Commission of Texas (PUCT). ERCOT is responsible for informing the PUCT of Retail Entities that do not meet their REC or Compliance Premium retirement obligations, of REC offset generators that do not produce generation sufficient to cover offsets they have been approved to provide, and of other anomalies which may come to ERCOT's attention through the administration of the REC Trading Program.

14.12 Maintain Public Information

(1) ERCOT shall maintain public information of interest to buyers and sellers of Renewable Energy Credits (RECs) or Compliance Premiums on the ERCOT website. The information provided shall include, at a minimum, a directory of all REC generators, Retail Entities, and other participants in the REC Trading Program. The directory shall include the following information:

(a) Name of the REC generator, Retail Entity, or other REC Account Holder;

(b) Name of the Designated Representative;

(c) Street address or post office box number;

(d) City, state or province, and zip or postal code;

(e) Country (if not the United States);

(f) Phone number;

(g) Fax number;

(h) E-mail address (with hypertext link); and

(i) Website address (with hypertext link).

(2) REC Account Holders shall describe their participation in the REC Trading Program using one or more of the following choices within a checkbox listing: REC generator, Retail Entity, REC broker, REC trader, REC trading exchange, REC aggregator, or other.

(3) Entities are responsible for notifying ERCOT of changes in the above information.

(4) ERCOT shall conspicuously display the following disclaimer in upper case and in bold font:

DISCLAIMER: ERCOT DOES NOT KNOW OR ENDORSE THE CREDIT WORTHINESS OR REPUTATION OF ANY REC ACCOUNT HOLDER LISTED IN THIS DIRECTORY.

(5) ERCOT may provide other information that describes the REC Trading Program, as it deems convenient or necessary for administering the REC Trading Program. ERCOT shall maintain a hypertext link to the appropriate pages on the Public Utility Commission of Texas' (PUCT's) website that are related to the REC Trading Program.

(6) ERCOT shall post each month the best available aggregated total energy sales (in MWh) of Retail Entities in Texas for the previous month and year-to-date for the calendar year. This posting shall be based on Retail Entity Loads provided in accordance with Section 14.5.2, Retail Entities.

(7) ERCOT shall post a list of Facility Identification Numbers, associated names, locations, and types.

14.13 Submit Annual Report to Public Utility Commission of Texas

(1) Beginning in 2002, ERCOT shall submit an annual report to the Public Utility Commission of Texas (PUCT) on or before the date set forth for such report in subsection (g)(11) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. Such report shall contain the following information pertaining to program operation for the previous Compliance Period:

(a) MW of existing renewable capacity installed in Texas, by technology type;

(b) MW of new renewable energy capacity installed in Texas, by technology type;

(c) List of eligible non-Texas capacity participating in the program, by technology type;

(d) Summary of Renewable Energy Credit (REC) aggregator activities, submitted in a format specified by the PUCT;

(e) Owner/operator of each REC generating facility;

(f) Date each new renewable energy facility began to produce energy;

(g) MWh of energy generated by renewable energy Resources as demonstrated through data supplied in accordance with these Protocols;

(h) List of renewable energy unit retirements;

(i) List of all Retail Entities participating in the REC Trading Program;

(j) Final RPS Requirement (FRR) of each Retail Entity;

(k) Number of REC offsets used by each Retail Entity;

(l) A list of REC offset generators, REC offsets awarded and MWh production from each such generator on an annual basis;

(m) Number of RECs retired by each program participant by category (mandatory compliance, voluntary retirement, expiration, and total retirements);

(n) Number of Compliance Premiums retired by each program participant by category (mandatory compliance, expiration, and total retirements);

(o) List of all Retail Entities in compliance with Renewable Portfolio Standard (RPS) requirement; and

(p) List of all Retail Entities not in compliance with RPS requirement including the number of RECs by which they were deficient.

ERCOT Nodal Protocols

Section 15: Customer Registration

October 1, 2022

15 CUSTOMER REGISTRATION 15-1

15 CUSTOMER REGISTRATION

(1) ERCOT shall maintain a registration database of all metered and unmetered Electric Service Identifiers (ESI IDs) in Texas for Customer Choice.

(2) ERCOT will notify the Public Utility Commission of Texas (PUCT) and the affected Competitive Retailer (CR) if a Transmission and/or Distribution Service Provider (TDSP) fails to meet its Customer switch responsibilities under the ERCOT Protocols.

(3) All CRs with Customers in Texas, whether operating inside the ERCOT Region or not, shall be required to register their Customers in accordance with this Section.

(4) All Customer registration processes will be conducted using the appropriate Texas Standard Electronic Transactions (TX SETs). Definitions of all TX SET codes referenced in this Section can be found in Section 19, Texas Standard Electronic Transaction. A reference to any TX SET transaction should be read as referring to the named transaction or its Market Information System (MIS) equivalent, if any. Transaction flow diagrams for Customer registration processing are posted on the ERCOT website.

(5) ERCOT will reject any initiating transaction due to date reasonableness if the requested implementation date is of more than 90 days in the future or 270 days in the past. Initiating transactions are: 814_01, Switch Request; 814_16, Move In Request; and 814_24, Move Out Request.

(6) ERCOT will prioritize initiating or inbound transactions in the following manner:

(a) Level 1 – Same day 814_16 transactions, same day 814_24 transactions, 814_01 transactions and 814_20, ESI ID Maintenance Requests (Create), will be processed in one Retail Business Hour.

(b) Level 2 – Standard 814_16 transactions and standard 814_24 transactions will be processed in two Retail Business Hours.

(c) Level 3 – 867_02, Historical Usage, 814_20, ESI ID Maintenance Requests (Maintain and Retire), will be processed in four Retail Business Hours.

(d) Level 4 – All 814_26, Historical Usage Requests, 814_18, Establish/Delete CSA Requests, and 814_19, Establish/Delete CSA Responses, will be processed in one Retail Business Day.

(7) For transactions to flow through ERCOT, back-dated transactions for a market-approved corrective action must meet the date reasonableness test. Market Participants must work with ERCOT for any manual changes to transactions that fall outside these dates for market-approved corrective action. However, a TDSP will reject a back-dated transaction that is not part of a market-approved transaction.

(8) For more information concerning the requirements for transaction processing in the retail market, please refer to the Retail Market Guide.

15.1 Customer Switch of Competitive Retailer

(1) The following process shall be followed for a Competitive Retailer (CR) to switch an Electric Service Identifier (ESI ID).

15.1.1 Submission of a Switch Request

(1) The CR shall submit a Switch Request to ERCOT using the 814_01, Switch Request. The Switch Request shall include, at a minimum, the five-digit zip code and an ESI ID. Within this transaction, the CR will also send information necessary for ERCOT to send a switch confirmation notice to the Customer as required by the applicable Public Utility Commission of Texas (PUCT) rules. The First Available Switch Date (FASD) is the day received by ERCOT unless received on a Sunday or an ERCOT holiday. If received on a Sunday or an ERCOT holiday, the FASD will be calculated as the next day that is not a Sunday or an ERCOT holiday.

15.1.1.1 Notification to Customer of Switch Request

(1) ERCOT will send a switch confirmation notice to the Customer as specified in the PUCT rules. This notice will give the Customer information regarding the Switch Request as described in the PUCT rules.

15.1.1.2 Provision of Historical Usage

(1) A request for historical usage may be submitted along with a Switch Request or as an ad hoc request.

15.1.1.2.1 Provision of Historical Usage with a Switch Request

(1) If requested by the switching CR in the Switch Request, the Transmission and/or Distribution Provider (TDSP) shall provide the most recent 12 months of historical usage, if available, to ERCOT, including monthly metered usage for the Customer's ESI ID and any applicable metered interval usage in accordance with the 867_02, Historical Usage. ERCOT's business process for Switch Requests is not linked to the receipt of the historical usage and the processing of the switch will continue regardless of the TDSP returning historical usage. Upon receipt of the historical usage from the TDSP, ERCOT shall forward the 867_02 transaction to the CR Data Universal Numbering System (DUNS) Number provided by the TDSP within four Retail Business Hours.

(2) Provision of meter read and historical usage data pursuant to this paragraph shall not be required when it would be prohibited by PUCT rules.

15.1.1.2.2 Ad Hoc Requests for Historical Usage

(1) To request historical usage on an ad hoc basis, the CR of Record must submit an 814_26, Historical Usage Request, to ERCOT. Within one Retail Business Day of receipt of an 814_26 transaction from a CR, ERCOT shall notify the TDSP of the ad-hoc request using the 814_26 transaction. The TDSP shall provide the requested information to ERCOT within two Retail Business Days of receipt of the 814_26 transaction using the 814_27, Historical Usage Response. ERCOT shall forward the usage information to the CR of Record using the 814_27 transaction within one Retail Business Day of receipt of the 814_27 transaction from the TDSP. The TDSP shall provide the most recent 12 months of historical usage, if available, to ERCOT, including monthly, metered usage for the Customer's ESI ID information and any applicable metered interval usage in accordance with the 867_02, Historical Usage. ERCOT will send the 867_02 transaction to the CR DUNS Number provided in the 867_02 transaction by the TDSP within four Retail Business Hours of receipt from the TDSP.

(2) Provision of meter read and historical usage data pursuant to this paragraph shall not be required when prohibited by PUCT rules.

15.1.1.3 Switch Enrollment Notification Request to TDSP

(1) ERCOT will submit to the TDSP serving the ESI ID, an enrollment notification request using the 814_03, Enrollment Notification Request, within one Retail Business Hour of the receipt of a valid Switch Request. The notification will include the name of the CR requesting service to the ESI ID and will indicate the FASD calculated pursuant to Section 15.1.1, Submission of a Switch Request.

15.1.1.4 Response from TDSP to Registration Notification Request

(1) Upon receipt of an enrollment notification request, the TDSP shall provide ESI ID information to ERCOT, including:

(a) ESI ID;

(b) Service Address;

(c) Rate class and sub-class, if applicable;

(d) Special needs indicator;

(e) Load Profile Type;

(f) Scheduled meter read date;

(g) Meter type, identification number, number of dials and role for each meter at the ESI ID if the ESI ID is metered;

(h) Number and description of each unmetered device for unmetered ESI IDs;

(i) Station ID; and

(j) Distribution Loss Factor (DLF) code.

(2) This information shall be transmitted using the 814_04, Enrollment Notification Response, within two Retail Business Days of the receipt of the 814_03, Enrollment Notification Request. If the TDSP does not respond with the ESI ID information within two Retail Business Days after the receipt of the 814_03 transaction from ERCOT, ERCOT shall create an internal tracking exception. The switch will be held in "in review" status until the TDSP's 814_04 transaction response is received. If the TDSP's 814_04 transaction is not received within three Retail Business Days of receipt of the 814_03 transaction from ERCOT and is still not received by the earlier of the requested date on the switch or within 20 Retail Business Days after the original submission of the 814_03 transaction from ERCOT, ERCOT shall change the status of the switch to "cancel pending." The TDSP will receive notification of the pending switch cancellation through the 814_08, Cancel Request. The TDSP will respond using the 814_09, Cancel Response. If the 814_09 transaction is an "accept," the submitting CR will receive notification of the switch cancellation through the 814_08 transaction. Any other CR involved in the request to which an 814_06, Loss Notification, has been sent will also receive notification of the switch cancellation through the 814_08 transaction. If the 814_09 transaction from the TDSP is a reject, the switch will return to an "in review" status and the TDSP shall also transmit an 814_04 transaction within one Retail Business Day.

(3) If the TDSP responds to ERCOT's 814_03 transaction with an 814_04 transaction and then later submits an 814_28, Complete Unexecutable or Permit Required, indicating the TDSP is unable to complete the switch, ERCOT will send the TDSP's 814_28 transaction to the requesting CR. The TDSP will note the complete unexecutable reason on the 814_28 transaction. The initiating transaction is considered unexecutable. The current CR will remain the CR of Record.

15.1.1.5 Response to Valid Enrollment Request

(1) Within one Retail Business Day of receipt of the TDSP's 814_04, Enrollment Notification Response, ERCOT will respond to the requesting CR in accordance with the 814_05, CR Enrollment Notification Response. This response will contain the scheduled meter read date for the switch and all information the TDSP furnished to ERCOT under the TDSP's 814_04 transaction. The TDSP must effectuate the switch within two Retail Business Days of the scheduled meter read date.

15.1.1.6 Loss Notification to Current Competitive Retailer (with date)

(1) Within two Retail Business Days of the scheduled meter read date for the switch, but not before the receipt of the TDSP's 814_04, Enrollment Notification Response, ERCOT will

notify the current CR using the 814_06, Loss Notification. This notification will contain the scheduled meter read date for the switch.

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 effective 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.

15.1.1.8 Rejection of Switch Request

(1) ERCOT will process Switch Requests upon receipt during Business Hours. If the request is invalid, i.e., meets one of the requirements as identified in this Section, ERCOT will respond to the CR with the 814_02, Switch Reject Response, within one Retail Business Hour of ERCOT's receipt of the Switch Request, and the switch process will terminate.

(2) ERCOT will reject a Switch Request using the 814_02 transaction for any of the following reasons:

(a) The ESI ID provided is inactive or does not exist;

(b) The ESI ID and five digit zip code do not match;

(c) The CR is not certified by the PUCT, if required;

(d) The CR is not authorized to provide service in the TDSP service area;

(e) The CR has not registered as a CR with ERCOT in accordance with Section 16, Registration and Qualification of Market Participants;

(f) The PUCT directs ERCOT to reject registration requests from the CR per applicable PUCT rules;

(g) The standard Switch Request was received after a valid standard Switch Request was scheduled for the same date;

(h) The CR specifies a billing type or bill calculation code for an ESI ID that is not supported by the TDSP, Municipally Owned Utility (MOU), or Electric Cooperative (EC);

(i) The CR submits a Switch Request type that is invalid or undefined;

(j) The CR is already the CR of Record for the ESI ID or scheduled to be the CR of Record for the ESI ID on the requested date;

(k) The Customer notification name or address is required but invalid according to Texas Standard Electronic Transaction (TX SET) standards or is missing;

(l) The CR Data Universal Numbering System (DUNS) Number is missing or invalid;

(m) If requesting a self-selected switch date, the CR requests a switch date that is before the FASD;

(n) The date on the self-selected switch already has a move in, move out, or switch scheduled; or

(o) The ESI ID is de-energized or scheduled to be de-energized on the date requested in the switch. For standard requests, the FASD is used for the evaluation.

15.1.2 Response from ERCOT to Drop to Affiliate Retail Electric Provider Request

(1) ERCOT will send a reject response using the 814_11, Drop Response, within one Retail Business Day to the current CR notifying the CR that the request is invalid.

15.1.3 Transition Process

(1) Certain circumstances may arise during the course of business in the Texas retail electric market that may necessitate the transition of ESI IDs from one CR to a Provider of Last Resort (POLR) or designated CR, or from one TDSP to another TDSP in quantities and

on a time frame that is not completely supported by standard market transactions or business processes.

15.1.3.1 Mass Transition Process

(1) In a Mass Transition event, ERCOT shall submit the 814_03, Enrollment Notification Request, requesting a meter read for the associated ESI IDs, for a date two days after the date ERCOT initiates such transactions to the TDSP. The 814_03 transaction shall contain a request for historical usage and the requested date 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. (See Retail Market Guide Section 9, Appendices, Appendix F2, Timeline for Initiation of a Mass Transition on a Business Day not Prior to a Weekend or ERCOT Holiday.)

(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 POLR(s) or 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, Appendix D1, Transaction Timing Matrix, for specific transaction timings.)

(3) ERCOT shall identify and monitor transitioned ESI IDs for a period of 60 days from the Mass Transition Date, as defined in the Retail Market Guide, to ensure that when a Customer switches away from the POLR, the 814_03 transaction is processed with a requested date equal to the FASD, regardless of how the switch was submitted. Identification of the transitioned ESI ID shall terminate either upon the first completed switch, move in, move out, or at the end of the 60 day period, whichever occurs first.

[NPRR1134: Replace paragraph (3) above with the following upon system implementation of RMGRR168:]

(3) ERCOT shall identify and monitor transitioned ESI IDs for a period of 60 days from the Mass Transition Date, as defined in the Retail Market Guide. Identification of the transitioned ESI ID shall terminate either upon the first completed switch, move in, move out, or at the end of the 60 day period, whichever occurs first.

(4) For a detailed outline of the business process and responsibilities of all Entities involved in a Mass Transition event, refer to the Retail Market Guide Section 7, Market Processes.

15.1.3.2 Acquisition Transfer Process

(1) In an acquisition 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 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 CRs with available Customer billing contact information for the ESI IDs the 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.

15.1.4 Beginning Service (New Construction Completed and Move Ins)

(1) This Section applies to Customers moving into a Premise that is not currently being served by a CR (may or may not still be energized) or when construction has been completed by the TDSP for a new Premise and the Premise has been assigned an ESI ID and is ready to receive electric service.

(2) This Section does not apply to instances where construction services are required. Those procedures are covered in the TDSP tariff.

15.1.4.1 Move-In Request to Begin Electric Service

(1) The process described below relates to the transactions required to process a move in. A manual work-around process for same day and safety net move ins is also used by Market Participants in the Texas retail electric market to ensure that a Customer receives electric service in a timely manner. The manual work-around process is documented in the Retail Market Guide.

(2) In accordance with PUCT rules, the Customer shall contact a CR to begin electric service at an ESI ID. The CR shall submit to ERCOT a Move-In Request in accordance with 814_16, Move In Request. Move ins will be considered same day, if the date requested is the same day the 814_16 transaction is processed at ERCOT. Same day move ins will be forwarded to the TDSP within one Retail Business Hour of receipt by ERCOT. Standard move ins, those move ins not requesting same day services, will be forwarded to the TDSP within one Retail Business Hour of receipt by ERCOT.

(3) Two Retail Business Days prior to the scheduled meter read date of the move in or upon receipt of the TDSP 814_04, Enrollment Notification Response, whichever is later, ERCOT will determine if the ESI ID is currently served or is scheduled to be served by another CR. If a move out from the current CR is scheduled for the same day as the move in, the TDSP will either complete both the move out and move in or will unexecute the move out, only working the move in. If, within four Retail Business Days of the scheduled date, the move out is still in a scheduled state, ERCOT shall cancel the move out and send cancellation notices to the TDSP and the respective CRs. ERCOT will submit an 814_06, Loss Notification, to the current CR with a code indicating a forced move out.

(4) If requested by the CR in the Move-In Request and permitted under the PUCT rules, the TDSP shall provide up to 12 months of the most recent historical usage, as available, including monthly-metered usage and any applicable metered interval usage using the 867_02, Historical Usage. ERCOT's business process for a Move-In Request is not linked to the receipt of the historical usage and the processing of the move in will continue regardless of the TDSP returning historical usage. This information shall be provided to the CR DUNS Number provided in the 867_02 transaction by the TDSP within four Retail Business Hours after ERCOT receipt of the 867_02 transaction from the TDSP. The TDSP shall respond within two Retail Business Days after receipt of the 814_03, Enrollment Notification Request. If historical usage is not available, the TDSP will indicate this in the 814_04, Enrollment Notification Response.

15.1.4.2 Response to Invalid Move-In Request

(1) If the Move-In Request is invalid, ERCOT will respond to the CR using the 814_17, Move In Reject Response, within one Retail Business Hour of receiving the 814_16,

Move In Request, with the exception of a move in that is invalid because of "Invalid ESI ID." In the case of "Invalid ESI ID," ERCOT will hold the Move-In 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. If the request is invalid in accordance with Section 15.1.4.8, Rejection of Move-In Request, the move in process will then terminate. If the request is valid, the process continues as described in Section 15.1.4.5, Response to Valid Move-In Request.

15.1.4.3 Notification to Transmission and/or Distribution Service Provider of Move In

(1) ERCOT will process Move-In Requests upon receipt during Business Hours. ERCOT will submit to the TDSP serving the ESI ID an 814_03, Enrollment Notification Request, within one Retail Business Hour of receiving a valid Move-In Request. The notification will include the name of the new CR providing service to the ESI ID and will include the requested move in date by the CR.

(2) If the TDSP receives the 814_03 transaction before 1700, a same day move in will be completed that day.

15.1.4.4 Response to Enrollment Notification Request from Transmission and/or Distribution Service Provider (Move In)

(1) Upon receipt of an enrollment notification request, the TDSP shall provide ESI ID information within the 814_04, Enrollment Notification Response, including:

   (a) ESI ID;

   (b) Service Address;

   (c) Rate class (if established*) and sub-class (if established*), if applicable;

   (d) Special needs indicator;

   (e) Load Profile Type;

   (f) Scheduled meter read date;

   (g) Meter type and role for each meter at the ESI ID, if ESI ID is metered;

   (h) Identification number and number of dials for each meter at the ESI ID, if ESI ID is metered (if meter is present);

   (i) For unmetered EDS IDs, number and description of each unmetered device (if devices are present*);

   (j) Station ID;

(k) DLF code;

(l) Premise type; and

(m) Meter reading cycle or meter cycle by day of the month.

* If not sent on the 814_04 transaction, the TDSP must send the rate class and sub-class on the 814_20, ESI ID Maintenance Request, when established, to complete the move in. The TDSP must send the 814_20 transaction prior to sending the monthly usage in the 867_03, Monthly or Final Usage. ERCOT will neither hold transactions nor validate the order of receipt of these transactions prior to sending to the CRs.

(2) If the TDSP does not respond with either the 814_04 transaction or the 814_28, Complete Unexecutable or Permit Required, within two Retail Business Days after receiving the 814_03, Enrollment Notification Request, ERCOT shall create an internal tracking exception. The move in will be held "in review" until the TDSP's 814_04 transaction or 814_28 transaction is received. If the TDSP's 814_04 transaction or 814_28 transaction, Permit Required, is not received within three Retail Business Days of receipt of the 814_03 transaction from ERCOT and is still not received by the earlier of the requested date on the move in or within 20 Retail Business Days after the original submission of the 814_03 transaction from ERCOT, ERCOT shall change the status of the move in to "cancel pending" status. The TDSP will receive notification of the pending cancellation through the 814_08, Cancel Request. The TDSP will respond using the 814_09, Cancel Response, within one Retail Business Day of receiving ERCOT's 814_08 transaction. If the 814_09 transaction is accepted, relevant CRs will receive notification of the cancellation through the 814_08 transaction. If the 814_09 transaction from the TDSP is a reject, the move in will return to an "in review" status and the TDSP shall also transmit an 814_04 transaction or 814_28 transaction, Permit Required, within one Retail Business Day.

(3) If the meter is present at the Premise at the time the TDSP receives the 814_03 transaction from ERCOT, and the TDSP responds with the 814_04 transaction, the information as identified in paragraph (1) above shall be transmitted from the TDSP to ERCOT using the 814_04 transaction. ERCOT shall forward ESI ID/Premise information using the 814_05, CR Enrollment Notification Response, to the requesting CR.

(4) If a meter has not been established at the ESI ID/Premise at the time when the TDSP receives the 814_03 transaction from ERCOT for a move in, the TDSP may respond with the 814_04 transaction without meter information, TDSP rate class and sub-class, and the number and description of un-metered devices to ERCOT. ERCOT shall forward the ESI ID/Premise information using the 814_05 transaction to the requesting CR. If the TDSP submits the 814_04 transaction with the information as identified in this paragraph, the TDSP will submit this missing information to ERCOT using the 814_20 transaction when established to complete the process. ERCOT shall forward the ESI ID/Premise

information received from the TDSP's 814_20 transaction to the requesting CR within four Retail Business Hours of receipt from the TDSP.

(5) If the TDSP responds to ERCOT's 814_03 transaction for a move in with an 814_28 transaction, Permit Required, ERCOT shall send this transaction within two Retail Business Hours to the requesting CR to notify that a permit is required. Upon receipt of the TDSP's 814_28 transaction, ERCOT will reset the 20 Retail Business Day clock, starting the clock on the requested date for the move in, and will separately track the non-response for the 814_04 transaction due to permit required. The move in remains in a "permit pending" status.

(6) After expiration of the 20 Retail Business Days, non-response for the 814_04 transaction because the TDSP has not received the permit, ERCOT will initiate the 814_08 transaction to the TDSP the first Retail Business Day after expiration of the 20 Retail Business Day clock, and will set the status to "cancel pending." The TDSP will respond to ERCOT using the 814_09 transaction. If the TDSP receives the appropriate permit prior to the receipt of the 814_08 transaction from ERCOT, the TDSP will submit the 814_04 transaction with the scheduled move in date and the 814_09 transaction with a status of reject and the move in process will proceed. If the TDSP responds with the 814_09 transaction with a status of accept, ERCOT will cancel the move in, note the cancel reason as "permit not received," and send the cancellation notice to the appropriate CRs.

(7) If the TDSP responds to ERCOT's 814_03 transaction with the 814_04 transaction, and then later submits the 814_28 transaction, ERCOT will send the TDSP's 814_28 transaction to the requesting CR. The TDSP will note the complete unexecutable reason on the 814_28 transaction. The initiating transaction is considered cancelled in ERCOT, TDSP and CR systems and the current CR remains the CR of Record for that Premise or the Premise remains in a de-energized status.

(8) If after submitting a 814_04 transaction on a forced move out, the TDSP is unable to obtain an actual meter read despite reasonable efforts the TDSP may complete the move in using an estimated meter read or complete unexecutable if the meter requires a permit, unsafe conditions exist, tampering has been detected or other similar conditions are found that would not allow an actual reading to be obtained.

15.1.4.5 Response to Valid Move-In Request

(1) ERCOT will respond to the CR using the 814_05, CR Enrollment Notification Response, within one Retail Business Hour of receiving the TDSP's 814_04, Enrollment Notification Response, on a same day or standard Move-In Request. This response will contain the scheduled meter read date for the move in and all other information contained in the TDSP's 814_04 transaction.

15.1.4.5.1 Maintain Electric Service Identifier with Meter Level Information Request/Response

(1) If the TDSP returns the 814_04, Enrollment Notification Response, without complete information (meter information and/or unmetered device(s) information), the TDSP is required to provide this information to ERCOT in the 814_20, ESI ID Maintenance Request, following the installation of the meter or unmetered devices. The TDSP must send the 814_20 transaction at the same time or prior to sending the 867_04, Initial Meter Read, to ERCOT. ERCOT will forward the meter information in the 814_20 transaction and the 867_04 transaction to the CR.

15.1.4.6 Notification to Current Competitive Retailer

(1) An evaluation is done on the current CR two Retail Business Days prior to the scheduled meter read date, but not before receipt of the TDSP's 814_04, Enrollment Notification Response. ERCOT will submit to the current CR a notification using the 814_06, Loss Notification, two days before the scheduled meter read date as set forth in the 814_04 transaction.

(2) If ERCOT has submitted a notification using the 814_06 transaction to the current CR before the TDSP sends the 814_28, Complete Unexecutable or Permit Required, to ERCOT, ERCOT will notify the current CR by forwarding the 814_28 transaction to the CR. The current CR will remain the CR of Record.

15.1.4.6.1 Complete Unexecutable

(1) After the new CR has received the Premise information in the 814_05, CR Enrollment Notification Response, the TDSP will wait until the scheduled move in date to energize the Premise. If upon the field visit to the Premise, the TDSP is unable to execute due to conditions that require Customer resolution and if power is not flowing to the Premise, the TDSP will send a notification request to ERCOT using the 814_28, Complete Unexecutable or Permit Required. The transaction will indicate the appropriate reason code for the complete unexecutable of the Move-In Request. If the move in has been complete unexecutable, ERCOT will internally flag the transaction as complete and will not expect the 867_04, Initial Meter Read, to complete the life cycle. ERCOT will respond to the TDSP using the 814_29, Complete Unexecutable or Permit Required Response.

(2) If ERCOT receives the 814_28, Complete Unexecutable or Permit Required, ERCOT will forward the notification to the CR. In this case the CR will not receive the 867_04 transaction. Once the condition has been corrected by the Customer, a new set of transactions must be initiated by the CR starting with the 814_16, Move In Request.

15.1.4.7 Completion of Move-In Request and Effective Move In Date

(1) If upon the field visit to the Premise, the TDSP is unable to obtain a meter read due to conditions that require Customer resolution but power is flowing to the Premise, the TDSP may complete the move in using an estimated meter read or complete unexecutable if the meter requires a permit, unsafe conditions exist, tampering has been detected, or other similar conditions are found that would not allow an actual reading to be taken.

15.1.4.7.1 Standard Move-In Requests

(1) A standard Move-In Request is effectuated on the period start date in the 867_04, Initial Meter Read, which shall be the date requested in the 814_16, Move In Request, provided that the 814_03, Enrollment Notification Request, was received by the TDSP by 1700 at least two Retail Business Days prior to the requested date. If the 814_03 transaction is not received by the TDSP by 1700 at least two Retail Business Days prior to the requested date, the move in will be completed within two Retail Business Days after the receipt of the 814_03 transaction by the TDSP. An extension of this period may be necessitated by circumstance requiring Customer resolution or construction of new facilities by the TDSP to serve the Premise.

(2) A Move-In Request is completed upon receipt of the effectuating meter read sent by the TDSP. Upon receipt, the TDSP will send initial meter read information to ERCOT and ERCOT shall resend to the CR DUNS Number provided in the 867_04 transaction by the TDSP within four Retail Business Hours using the 867_04 transaction. The 867_04 transaction will be provided to ERCOT within three Retail Business Days of the meter read.

(3) The move in will 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 move in is effective at 0000 (midnight) the day of the special meter read. Meter reads will be sent to the CR DUNS Number within the TX SET transaction from the TDSP within 12 hours of receipt by ERCOT.

15.1.4.7.2 Same Day Move-In Requests

(1) A same day Move-In Request is effectuated on the period start date in the 867_04, Initial Meter Read, which shall be the date requested in the 814_16, Move In Request, provided that the request was received by the TDSP by 1700 on the date requested. If the TDSP does not receive the same day move in by 1700, the move in will be completed no later than the next Retail Business Day. An extension of this period may be necessitated by circumstance requiring Customer resolution or construction of new facilities by the TDSP to serve the Premise.

(2) A Move-In Request is completed upon receipt of the effectuating meter read sent by the TDSP. Upon receipt, the TDSP will send initial meter read information to ERCOT and ERCOT shall resend to the CR DUNS Number provided in the 867_04 transaction by the TDSP within four Retail Business Hours using the 867_04 transaction. The 867_04 transaction will be provided to ERCOT within three Retail Business Days of the meter read.

(3) The move in will 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 move in is effective at 0000 (midnight) the day of the special meter read. Meter reads will be sent to the CR DUNS Number within the TX SET transaction from the TDSP within 12 hours of receipt by ERCOT.

15.1.4.8 Rejection of Move-In Request

(1) ERCOT will reject the 814_16, Move In Request, using the 814_17, Move In Reject Response, for any of the following reasons:

(a) The ESI ID provided is inactive or does not exist;

(b) The ESI ID and five-digit zip code do not match;

(c) The CR is not certified by the PUCT, if required;

(d) The CR is not authorized to provide service in the TDSP service area.

(e) CR has not registered as a CR with ERCOT in accordance to Section 16, Registration and Qualification of Market Participants.

(f) The PUCT directs ERCOT to reject registration requests from the CR per applicable PUCT rules;

(g) The CR specifies a billing type or billing calculation code for an ESI ID that is not supported by the TDSP, MOU, or EC;

(h) The CR submits a request type that is invalid or undefined;

(i) The CR DUNS Number is missing or invalid; or

(j) There is already a Move-In Request in progress for the same requested date, "not first in" for the same requested date.

15.1.5 Service Termination (Move Out)

15.1.5.1 Request to Terminate Service

(1) When a CR receives notice that a Customer is moving out, the CR may terminate service to that ESI ID by submitting a Move-Out Request to ERCOT using the 814_24, Move Out Request. Move outs will be considered same day, if the date requested is the same day the 814_24 transaction is processed at ERCOT. Same day move outs will be forwarded to the TDSP within one Retail Business Hour of receipt by ERCOT. Standard move outs, those move outs not requesting same day services, will be forwarded to the TDSP within two Retail Business Hours of receipt by ERCOT. This transaction will remove the requester as the CR of Record for that ESI ID. If the submitting CR did not include the "Ignore CSA" flag on the move out, ERCOT will determine if the ESI ID associated with the Premise has a Continuous Service Agreement (CSA) CR. If there is a CSA on record, ERCOT will notify the CSA CR of the move out (refer to Section 15.1.9, Continuous Service Agreement CR Processing) using the 814_22, CSA CR Move In Request, within two Retail Business Days of the scheduled meter read date, but not before the receipt of the TDSP's 814_04, Enrollment Notification Response. If there is not a CSA CR, ERCOT will notify the TDSP to de-energize the ESI ID.

[NPRR1095: Replace paragraph (1) above with the following upon system implementation:]

(1) When a CR receives notice that a Customer is moving out, the CR may terminate service to that ESI ID by submitting a Move-Out Request to ERCOT using the 814_24, Move Out Request. Move outs will be considered same day, if the date requested is the same day the 814_24 transaction is processed at ERCOT. Same day move outs will be forwarded to the TDSP within one Retail Business Hour of receipt by ERCOT. Move outs not requesting same day services, will be forwarded to the TDSP within two Retail Business Hours of receipt by ERCOT.

(2) ERCOT will determine if the ESI ID associated with the Premise has a Continuous Service Agreement (CSA) CR.

(a) If there is an active CSA on record or a CSA with a start date prior to or equal to the requested date of the move out, ERCOT will notify the TDSP by sending the 814_03, Enrollment Notification Request, with the move out indicator, within one Retail Business Hour for same day requests and two Retail Business Hours for move outs not requesting same day services. ERCOT will notify the CSA CR of the move out using the 814_22, CSA CR Move In Request, within two Retail Business Days of the scheduled meter read date, but not before the receipt of the TDSP's 814_04, Enrollment Notification Response.

(b) If there is not an active CSA CR or a CSA with a start date prior to or equal to the requested date of the move out, ERCOT will notify the TDSP to de-energize the ESI ID by sending the 814_24 transaction and will remove the requester as the CR of

Record for that ESI ID.

(3) When requesting to terminate service where a CSA exists, the CSA CR may terminate service to that ESI ID by submitting an 814_24 transaction with the "Move Out CSA De-Energize" code to ERCOT. ERCOT will validate that the submitting CR is the current CSA CR of Record. If the submitting CR is not the current CSA CR of Record, ERCOT will reject the 814_24 transaction by sending the 814_25, Move Out Response. Move outs will be considered same day if the date requested is the same day the 814_24 transaction is processed at ERCOT. Same day move outs will be forwarded to the TDSP within one Retail Business Hour of receipt by ERCOT. Move outs not requesting same day services will be forwarded to the TDSP within two Retail Business Hours of receipt by ERCOT.

15.1.5.2 Response to Invalid Move-Out Request

(1) If the Move-Out Request is invalid, ERCOT will respond to the CR using the 814_25, Move Out Response, within one Retail Business Hour of receiving the 814_24, Move Out Request, with the exception of a move out that is invalid because of "de-energized ESI ID." In the case of "de-energized ESI ID," ERCOT will hold the Move-Out 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. If the request is invalid, the move out process will then terminate. If the request is valid, the process continues as described in Section 15.1.5.5, Response to Valid Move-Out Request and Continuous Service Agreement in Effect.

15.1.5.3 Notification to Transmission and/or Distribution Service Provider of Move Out

(1) ERCOT will process Move-Out Requests upon receipt during Business Hours.

(2) If there is a CSA CR for the ESI ID, ERCOT will submit to the TDSP serving the ESI ID a registration notification request using the 814_03, Enrollment Notification Request, within one Retail Business Hour of receiving a valid same day Move-Out Request and within two Retail Business Hours after receipt of the standard Move-Out Request. The notification will include the move out date requested by the CR.

(3) If there is not a CSA CR, ERCOT will notify the TDSP serving the ESI ID of the termination notification within one Retail Business Hour of receiving a valid same day Move-Out Request and within two Retail Business Hours after receipt of the standard Move-Out Request using the 814_24, Move Out Request. The notification to the TDSP will include the move out date requested by the CR.

15.1.5.4 Response to Enrollment Notification Request/Service Termination from Transmission and/or Distribution Service Provider

(1) If there is a CSA CR, upon receipt of an Enrollment notification request, the TDSP shall provide ESI ID information, including:

(a) ESI ID;

(b) Service Address;

(c) Rate class and sub-class (if applicable);

(d) Any and all applicable riders;

(e) Special needs indicator;

(f) Load Profile Type;

(g) Scheduled meter read date;

(h) Meter type, identification number, number of dials and role for each meter at the ESI ID, if ESI ID is metered;

(i) For unmetered EDS IDs, number and description of each unmetered device;

(j) Load bus identification; and

(k) DLF code.

(2) This information shall be transmitted by the TDSP using the 814_04, Enrollment Notification Response, and shall be provided to the CSA CR by ERCOT in the form of an 814_22, CSA CR Move In Request, within two Retail Business Days of the scheduled meter read date on the move out to CSA. Items (1)(a) and (1)(g) above shall be forwarded to the submitting CR by ERCOT in the form of an 814_25, Move Out Response. If the TDSP does not respond with ESI ID information within two Retail Business Days after the submission of the 814_03, Enrollment Notification Request, from ERCOT, ERCOT shall create an internal tracking exception. The move out to CSA will be held in “in review” status until the TDSP’s 814_04 transaction is received. If the TDSP’s 814_04 transaction is not received within three Retail Business Days of submission of the 814_03 transaction by ERCOT and is still not received by the earlier of the requested date on the move out to CSA or 20 Retail Business Days after the original submission of the 814_03 transaction from ERCOT, ERCOT shall change the status of the move out to CSA to “cancel pending.” The TDSP will receive notification of the pending cancellation through the 814_08, Cancel Request. The TDSP will respond using the 814_09, Cancel Response. If the 814_09 transaction is an accept, relevant CRs will receive notification of the cancellation through the 814_08 transaction. If the 814_09 transaction from the TDSP is a reject, the move out to CSA will return to an “in review”

status and the TDSP shall also transmit an 814_04 transaction within one Retail Business Day.

(3) If there is not a CSA CR, upon receipt of a service termination request, the TDSP shall provide ESI ID information, including:

(a) ESI ID; and

(b) Scheduled meter read date.

(4) This information shall be transmitted using the 814_25 transaction and shall be provided by ERCOT to the submitting CR within two Retail Business Hours from ERCOT's receipt of the TDSP's 814_25 transaction. If the TDSP does not respond with ESI ID information within two Retail Business Days after the submission of the 814_24, Move-Out Request, by ERCOT, ERCOT shall create an internal tracking exception. The move out will be held in "in review" status until the TDSP's 814_25 transaction is received. If the TDSP's 814_25 transaction is not received within three Retail Business Days of submission of the 814_24 transaction by ERCOT and is still not received by the earlier of the requested date on the move out or 20 Retail Business Days after the original submission of the 814_24 transaction by ERCOT, ERCOT shall change the status of the move out to "cancel pending." The TDSP will receive notification of the pending cancellation through the 814_08, Cancel Request. The TDSP will respond in accordance with the 814_09, Cancel Response. If the 814_09 transaction from the TDSP is a reject, the move out will return to an "in review" status and the TDSP shall also transmit an 814_25 transaction within one Retail Business Day.

(5) If the TDSP responds to ERCOT's 814_24 transaction with an 814_25 transaction, and then later submits an 814_28, Complete Unexecutable or Permit Required, indicating the TDSP is unable to complete the move out, ERCOT will send the TDSP's 814_28 transaction to the requesting CR. The TDSP will note the complete unexecutable reason on the 814_28 transaction. The initiating transaction is considered unexecutable. The current CR will remain the CR of Record.

(6) If, despite reasonable efforts, the TDSP is unable to complete the move out after submitting the 814_25 transaction, it shall unexecute the move out using the 814_28 transaction, Complete Unexecutable, and the TDSP shall note the complete unexecutable reason on the 814_28 transaction. ERCOT shall forward the 814_28 transaction to the CR within two Retail Business Hours of receipt from the TDSP.

(7) Upon receipt of the 814_28 transaction, the CR will make reasonable attempts to contact the Customer to address access issues if the reason the transaction was unexecuted relates to meter access. Otherwise, the CR will contact the TDSP in an attempt to address the problems that precluded execution of the transaction. TDSPs shall provide CRs with a list of contacts for this purpose, including escalation contacts which shall be used by a CR only in the event that the initial contacts fail to respond to the CR within a reasonable time.

(8) After the CR has made reasonable efforts to either contact the Customer or address issues with the TDSP, the CR may submit a second 814_24 transaction to initiate the move out process. The CR will submit the second Move-Out Request within 30 days of the receipt of the 814_28 transaction. If the TDSP continues to encounter difficulty in completing the transaction, the TDSP shall complete the transaction using an estimated meter read and make every reasonable effort to interrupt service at the premise to prevent additional cost to the market, such as Unaccounted for Energy (UFE) and repeated field trips executed by the TDSP to disconnect service or in management of the market-approved manual process for managing the left in hot process. For Customers who are critical care or critical Load, the CR will contact the appropriate TDSP Retail Electric Provider (REP) relations personnel to address the request.

15.1.5.5 Response to Valid Move-Out Request and Continuous Service Agreement in Effect

(1) Two Retail Business Days prior to the scheduled meter read date, but not prior to the receipt of the TDSP's 814_04, Enrollment Notification Response, ERCOT will send response information to the CSA CR using the 814_22, CSA CR Move In Request. This notice will contain the confirmed meter read date for the move out. This date will be the start date for the CSA CR to begin serving the ESI ID.

15.1.5.6 Completion of Move-Out Request and Effective Move Out Date

(1) A Move-Out Request is effectuated on the actual meter read date in the final 867_03, Monthly of Final Usage, which shall be the date requested in the 814_24, Move Out Request, provided that the request was received by the TDSP by 1700 and at least two Retail Business Days prior to the date requested. If the request is not received by the TDSP by 1700 at least two days prior to the requested date, the request will be completed within two Retail Business Days after the Move-Out Request is received by the TDSP. An extension of this period may be necessitated by circumstances requiring Customer resolution, in which case the TDSP may provide an 814_28, Complete Unexecutable or Permit Required, to the CR.

(2) A Move-Out Request is completed upon receipt of the effectuating meter read sent by the TDSP. The TDSP shall send the meter read information to ERCOT using the final 867_03 transaction, within three Retail Business Days of the meter read. 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 CSA CR DUNS Number provided in the 867_04 transaction by the TDSP (if applicable) within four Retail Business Hours using the 867_03 transaction and 867_04, Initial Meter Read, as appropriate.

(3) The move out will become effective at 0000 (midnight) on the actual date of the effectuating meter read. The current 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.

(4) For a special meter read, the move out is effective at 0000 (midnight) the day of the special meter read. Meter reads will be sent to the CR DUNS Number within the TX SET transaction from the TDSP within 12 hours of receipt by ERCOT.

15.1.5.7 Rejection of Move-Out Request

(1) ERCOT will reject a Move-Out Request using the 814_25, Move Out Response, for any of the following reasons:

(a) The ESI ID provided is inactive or does not exist;

(b) The ESI ID and five-digit zip code do not match;

(c) The request type is invalid or undefined;

(d) The CR's DUNS Number is missing or invalid;

(e) The requesting CR is not the current CR and not scheduled to be the CR on the requested date after a retry period of 48 hours counting only hours on Retail Business Days but not only Business Hours; or

(f) The move out is requesting a date that is scheduled on another move out.

[NPRR1095: Insert paragraphs (g) and (h) below upon system implementation:]

(g) The requesting CR is not the current CSA CR and uses the "Move Out CSA De-Energize" code; or

(h) The requesting CR is not the current CSA CR and uses both the "Move Out CSA De-Energize" and the "Drop and Investigate Removal of Meter and Service" codes.

15.1.6 Concurrent Processing

(1) Concurrent processing permits multiple requests to proceed at the same time. The purpose of concurrent processing is to assure all valid transactions are accepted and processed according to a set of market rules. The order of precedence for initiating retail transactions is:

(a) Move-In Requests;

(b) Move-Out Requests; and

(c) Switch Requests.

(2) When performing concurrent processing checks, ERCOT will first perform standard validations to ensure the requests are valid. This validation can be found in Section 15.1,

Customer Switch of Competitive Retailer, Section 15.1.4, Beginning Service (New Construction Completed and Move Ins), and Section 15.1.5, Service Termination (Move Out).

15.1.6.1 Move In Date Prior to or After Move Out Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move in and move out scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If the move in scheduled meter read date is not equal to the move out scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete. If the submitting CR is not scheduled to be the CR of Record on the scheduled meter read date of the move out, ERCOT cancels the move out.

15.1.6.2 Move In Date Equal to Move Out Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move in and move out scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If the move in scheduled meter read date is equal to the move out scheduled meter read date, the move out transaction is cancelled by ERCOT. If the move out is not scheduled, but the requested date is equal to the scheduled date for the move in, the move out transaction is cancelled by ERCOT.

(2) If the ERCOT evaluation is performed for a same day move in and a move out is already scheduled for the current day, ERCOT will not cancel the move out and will leave it in a scheduled status. If the TDSP chooses not to work the move out the TDSP will complete unexecute the move out. In the event the move out is not complete or complete unexecutable by the TDSP within four Retail Business Days, ERCOT will cancel the move out.

15.1.6.3 Move In Date Prior to or Equal to Switch Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move in scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If there is a switch with a scheduled meter read date after or equal to the move -in scheduled meter read date, the switch transaction is cancelled by ERCOT. If the switch is not scheduled, but the requested date (FASD for standard switches) is after or equal to the scheduled date for the move in, the switch transaction is cancelled by ERCOT.

15.1.6.4 Move In Date After Switch Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move in scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If the move in scheduled meter read date is after a switch scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete.

15.1.6.5 Move In Date After Mass Transition Drop Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move in scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If the move in scheduled meter read date is after a Mass Transition drop scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete.

15.1.6.6 Move Out Date Prior to or Equal to Switch Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move out scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If there is a switch with a scheduled meter read date after or equal to the move out scheduled meter read date, the switch transaction is cancelled by ERCOT. If the switch is not scheduled, but the requested date (FASD for standard switches) is after or equal to the scheduled date for the move out, the switch transaction is cancelled by ERCOT.

15.1.6.7 Move Out Date After Switch Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move out scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If the move out scheduled meter read date is after a switch scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete. If the submitting CR is not scheduled to be the CR of Record on the scheduled meter read date of the move out, ERCOT cancels the move out.

15.1.6.8 Move Out Date After Mass Transition Drop Date

(1) ERCOT performs evaluations two Retail Business Days prior to all move out scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If the move out scheduled meter read date is after a Mass Transition drop scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete. If the submitting CR is not scheduled to be the CR of Record on the scheduled meter read date of the move out, ERCOT cancels the move out.

15.1.6.9 Multiple Switches

(1) ERCOT performs evaluations two Retail Business Days prior to all switch scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If there is another switch with a scheduled meter read date after or prior to the switch scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete. If there is another switch with a scheduled meter read date equal to the switch scheduled meter read date and neither have a “cancel pending” status, ERCOT will cancel the second switch received based on receipt date/time of the initiating

transaction. If one of the switches has a “cancel pending” status, it will be cancelled by ERCOT and the other one will be allowed to complete.

15.1.6.10 Multiple Move Ins

(1) ERCOT performs evaluations two Retail Business Days prior to all move in scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If there is another move in with a scheduled meter read date after or prior to the move in scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete. If there is another move in with a scheduled meter read date equal to the move in scheduled meter read date and neither have a “cancel pending” status ERCOT will cancel the second move in received based on receipt date/time of the initiating transaction. If one of the move ins has a “cancel pending” status it will be cancelled by ERCOT and the other one will be allowed to complete.

15.1.6.11 Multiple Move Outs

(1) ERCOT performs evaluations two Retail Business Days prior to all move out scheduled meter read dates or upon the receipt of the TDSP response, whichever is later. If there is another move out with a scheduled meter read date after or prior to the move out scheduled meter read date, both processes will run concurrently and both processes will be allowed to complete. If the submitting CR is not scheduled to be the CR of Record on the scheduled meter read date of the move out, ERCOT cancels the move out. If there is another move out with a scheduled meter read date equal to the move out scheduled meter read date and neither have a “cancel pending” status, ERCOT will cancel the second move out received based on receipt date/time of the initiating transaction. If one of the move outs has a “cancel pending” status, it will be cancelled by ERCOT and the other one will be allowed to complete.

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 CR on a move in if ERCOT has already sent the 814_06, Loss Notification, to the losing CR. ERCOT will only send the 814_12 transaction to the 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.

15.1.8 Cancellation of Registration Transactions

(1) The CR will send a cancellation notice using the 814_08, Cancel Request. ERCOT will accept cancellations on or before the day preceding the move in, move out or switch scheduled date. ERCOT will reject any 814_08 transaction received on the scheduled move in, move out or switch date, as well as cancellation requests on orders that were scheduled in the past.

(2) If the cancellation does not pass validation, ERCOT will reply to the CR within two Retail Business Hours with a rejection of the cancellation notice using the 814_09, Cancel Response, with the exception of a cancellation that is invalid because of “Item or Service Not Established.” In the case of “Item or Service Not Established,” ERCOT will hold the cancellation 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 cancellation notice is accepted, ERCOT will set the status to “cancel pending” status and notify the TDSP within two Retail Business Hours using the 814_08 transaction. If the TDSP accepts the cancel, ERCOT will cancel the transaction and notify the submitting CR using the 814_09 transaction. When ERCOT has sent the current CR an 814_06, Loss Notification, the current CR will be sent an 814_08 transaction. On a move out to CSA, if ERCOT has sent the 814_22, CSA CR Move In Request, to the CSA CR, the CSA CR will be sent an 814_08 transaction. If the TDSP rejects the cancel, ERCOT will reset the status to “in review,” “permit pending,” or “scheduled” as appropriate, and forward the reject to the CR. The TDSP will respond within one Retail Business Day using the 814_09 transaction.

15.1.9 Continuous Service Agreement CR Processing

(1) This Section sets forth the processes to initiate or terminate a CSA.

15.1.9.1 Request to Initiate Continuous Service Agreement in an Investor Owned Utility Service Territory

(1) When a CR establishes a CSA at an ESI ID, the CR will send an 814_18, Establish/Delete CSA Request, to ERCOT. ERCOT will determine if the ESI ID has a

CSA on record. If there is a current CSA CR, ERCOT will send notice of CSA termination using the 814_18, Establish/Delete CSA Request, within one Retail Business Day of receipt of the 814_18 transaction from the new CSA CR and will respond to the new CSA CR using the 814_19, Establish/Delete CSA Response, within one Retail Business Day of receipt of the 814_18 transaction. If there is not a current CSA, ERCOT will respond to the new CSA CR using the 814_19, Establish/Delete CSA Response, within one Retail Business Day of receipt of the 814_18 transaction.

[NPRR1095: Replace paragraph (1) above with the following upon system implementation and renumber accordingly:]

(1) When a CR establishes a CSA at an ESI ID, the CR will send an 814_18, Establish/Delete CSA Request, to ERCOT. ERCOT will determine if the ESI ID has a CSA on record. If there is not a current CSA, ERCOT will respond to the new CSA CR using the 814_19, Establish/Delete CSA Response, within one Retail Business Day of receipt of the 814_18 transaction. ERCOT will hold the CSA in a pending status until the start date of the CSA.

(2) If there is a current CSA, ERCOT will respond to the new CSA CR using the 814_19 transaction within one Retail Business Day of receipt of the 814_18 transaction. On the start date of the new CSA, ERCOT will send notice of CSA termination using the 814_18 transaction to the current CSA.

(2) If a CSA CR wishes to establish CSAs with multiple ESI IDs, the CSA CR must submit an 814_18 transaction for each ESI ID.

15.1.9.2 Request to Terminate Continuous Service Agreement

(1) The CSA CR will send an 814_18, Establish/Delete CSA Request, to ERCOT. ERCOT will respond to the CR using the 814_19, Establish/Delete CSA Response.

(2) If the CSA CR wishes to terminate CSAs with multiple ESI IDs, the CR must submit an 814_18 transaction for each ESI ID.

15.1.9.3 Notice to Continuous Service Agreement Competitive Retailer of Enrollment Due to a Move Out

(1) If, during the processing of a Move-Out Request, ERCOT determines that a CSA CR exists for the ESI ID, ERCOT will notify the CSA CR of the move out (refer to Section 15.1.5, Service Termination (Move Out)) using the 814_22, CSA CR Move In Request, within two Retail Business Days of the scheduled meter read date, but not before the receipt of the TDSP's 814_04, Enrollment Notification Response. This request will contain all of the information necessary for the CSA CR to begin servicing the ESI ID, including the move out date.

[NPRR1095: Replace paragraph (1) above with the following upon system implementation:]

(1) If, during the processing of a Move-Out Request, ERCOT determines that a CSA CR exists and has an end date after the requested date for the move out, ERCOT will notify the CSA CR of the move out (refer to Section 15.1.5, Service Termination (Move Out)) using the 814_22, CSA CR Move In Request, within two Retail Business Days of the scheduled meter read date, but not before the receipt of the TDSP's 814_04, Enrollment Notification Response. This request will contain all of the information necessary for the CSA CR to begin servicing the ESI ID, including the move out date.

(2) If the CSA CR requires historical usage information for the ESI ID, the CSA CR will submit a request using the 814_26, Historical Usage Request, after receipt of the 867_04, Initial Meter Read.

15.1.9.4 Notice to Continuous Service Agreement Competitive Retailer of Drop Due to a Move In

(1) An evaluation is done on the CSA CR two Retail Business Days prior to the scheduled meter read date, but not before receipt of the TDSP's 814_04, Enrollment Notification Response. If ERCOT determines that there is a CSA CR or there is scheduled to be a CSA CR on the scheduled meter read date, ERCOT will submit to the CSA CR a notification using the 814_06, Loss Notification.

(2) If ERCOT has submitted a notification using the 814_06 transaction to the CSA CR and then the TDSP sends the 814_28, Complete Unexecutable or Permit Required, to ERCOT, ERCOT will notify the CSA CR by submitting the 814_28 transaction. The CSA CR will remain the CR of Record.

15.1.10 Continuous Service Agreement Competitive Retailer Processing in Municipally Owned Utility/Electric Cooperative Service Territory

(1) This Section sets forth the processes to initiate or terminate a CSA in a MOU or EC service territory.

15.1.10.1 Request to Initiate Continuous Service Agreement

(1) When a CR establishes a CSA at an ESI ID, the CR will send an 814_18, Establish/Delete CSA Request, to ERCOT. This will be forwarded to the MOU/EC TDSP within one Retail Business Day. ERCOT will send the 814_18 transaction, and if an 814_19, Establish/Delete CSA Response, is not received from the MOU/EC TDSP within ten Business Days, ERCOT will cancel the CSA request and send an 814_08, Cancel Request, to the requesting CSA CR and MOU/EC TDSP. Additional 814_18 transactions received on the ESI ID while the first 814_18 transaction is still pending will be rejected at ERCOT. If an 814_18 transaction is received on an ESI ID with an

existing CSA relationship, ERCOT will forward the 814_18 transaction to the MOU/EC TDSP within one Retail Business Day, and upon receipt of the 814_19 transaction (accept) from the MOU/EC TDSP, will send an 814_18 transaction to the current CSA CR and an 814_19 transaction to the new CSA CR within one Retail Business Day of receipt of the 814_19 transaction from the MOU/EC TDSP.

[NPRR1095: Replace paragraph (1) above with the following upon system implementation and renumber accordingly:]

(1) When a CR establishes a CSA at an ESI ID, the CR will send an 814_18, Establish/Delete CSA Request, to ERCOT. This will be forwarded to the MOU/EC TDSP within one Retail Business Day. ERCOT will send the 814_18 transaction, and if an 814_19, Establish/Delete CSA Response, is not received from the MOU/EC TDSP within ten Business Days, ERCOT will cancel the CSA request and send an 814_08, Cancel Request, to the requesting CSA CR and MOU/EC TDSP. Additional 814_18 transactions received on the ESI ID while the first 814_18 transaction is still pending will be rejected at ERCOT. Upon receipt of the 814_19 transaction (accept) from the MOU/EC TDSP, ERCOT will send an 814_19 transaction to the new CSA CR within one Retail Business Day. ERCOT will hold the CSA in a pending status until the start date of the CSA.

(2) If an 814_18 transaction is received on an ESI ID with an existing CSA relationship, ERCOT will forward the 814_18 transaction to the MOU/EC TDSP within one Retail Business Day, and upon receipt of the 814_19 transaction (accept) from the MOU/EC TDSP, will send an 814_19 transaction to the new CSA CR within one Retail Business Day of receipt of the 814_19 transaction from the MOU/EC TDSP. ERCOT will hold the CSA in a pending status until the start date of the CSA. On the start date of the new CSA, ERCOT will send notice of the CSA termination using the 814_18 transaction to the current CSA.

(2) If a CSA CR wishes to establish CSAs with multiple ESI IDs, the CSA CR must submit an 814_18 transaction for each ESI ID.

15.1.10.2 Request to Terminate Continuous Service Agreement

(1) The CSA CR will send an 814_18, Establish/Delete CSA Request, to ERCOT. Upon receipt of an 814_18 transaction, ERCOT will terminate the CSA relationship, send an 814_19, Establish/Delete CSA Response, to the CSA CR, and forward the 814_18 transaction to the TDSP. An 814_18 transaction received while an 814_18 Establish transaction is pending will delete the current CSA relationship at ERCOT, provided the CSA CR of the 814_18 transaction and the current active CSA CR is the same.

(2) If CSA CR wishes to terminate CSAs with multiple ESI IDs, the CSA CR must submit an 814_18 transaction for each ESI ID.

15.1.10.3 Notice to Continuous Service Agreement Competitive Retailer of Enrollment Due to a Move Out

(1) If, during the processing of a Move-Out Request, ERCOT determines that a CSA CR exists for the ESI ID, ERCOT will notify the CSA CR of the move out (refer to Section 15.1.5, Service Termination (Move Out)) using the 814_22, CSA CR Move In Request, within two Retail Business Days of the scheduled meter read date, but not before the receipt of the MOU/EC TDSP's 814_04, Enrollment Notification Response. This request will contain all of the information necessary for the CSA CR to begin servicing the ESI ID including the move out date.

(2) If the CSA CR requires historical usage information for the ESI ID, the CSA CR will submit a request using the 814_26, Historical Usage Request, after receipt of the 867_04, Initial Meter Read.

15.1.10.4 Notice to Continuous Service Agreement Competitive Retailer of Drop Due to a Move In

(1) An evaluation is done on the CSA CR two Retail Business Days prior to the scheduled meter read date, but not before receipt of the MOU/EC TDSP's 814_04, Enrollment Notification Response. If ERCOT determines that there is a CSA CR or there is scheduled to be a CSA CR on the scheduled meter read date, ERCOT will submit to the CSA CR a notification using the 814_06, Loss Notification.

(2) If ERCOT has submitted a notification using the 814_06 transaction to the CSA CR and then the TDSP sends the 814_28, Complete Unexecutable or Permit Required, to ERCOT, ERCOT will notify the CSA CR by forwarding the 814_28 transaction. The CSA CR will remain the CR of Record.

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.

15.2.1 Find ESI ID Function on the Market Information System

(1) Market Participants with an ERCOT digital certificate can obtain information to verify the Service Address for a Service Delivery Point using the Find ESI ID function on the Market Information System (MIS) Secure Area. The Find ESI ID function returns the information as identified in Section 15.2, Database Queries.

15.2.2 Find Transaction Function on the Market Information System

(1) Competitive Retailers (CRs) or TDSPs with an ERCOT digital certificate may obtain transaction information from ERCOT to review business processes (i.e. Switch Request, Move-In Request, etc.) on ESI IDs. The Find Transaction function provides both summary and detailed transaction information for an ESI ID. The data displayed is confidential information and therefore is restricted by digital certificate. Access to the ESI ID information displayed is limited based on transaction receiver/sender, TDSP ownership, or the Retail Electric Provider (REP) of Record for each ESI ID. MIS help screens provide detailed descriptions of the field contents and related screens.

15.2.3 Electric Service Identifier Extract on the Market Information System

(1) ERCOT posts a downloadable extract to the ERCOT website which contains the same information as listed in Section 15.2, Database Queries. The information provided allows Entities that do not have a digital certificate and are unable to access the information through the Find ESI ID function to use the information to determine or to verify the ESI ID for a Service Delivery Point using the Service Address. This extract is also used by Entities to incorporate ESI ID information into their database systems.

15.3 Monthly Meter Reads

(1) Each Transmission and/or Distribution Service Provider (TDSP) shall send monthly consumption information for all non-ERCOT-Polled Settlement (EPS) Meter Electric Service Identifiers (ESI IDs) within its service area to ERCOT not later than three Retail

Business Days after the scheduled meter read cycle or scheduled meter cycle by day of the month for a point of delivery, using the 867_03, Monthly or Final Usage. TDSPs shall send monthly consumption information for all ESI IDs associated with EPS-metered facilities to ERCOT no later than three Retail Business Days after TDSP receipt of daily EPS Meter data from ERCOT according to the TDSP scheduled meter read cycle or scheduled meter cycle by day of the month for a point of delivery, using the 867_03 transaction. ERCOT will forward ERCOT-accepted consumption information to the Competitive Retailer (CR) Data Universal Numbering System (DUNS) Number provided in the 867_03 transaction by the TDSP within 12 hours.

(2) If the meter read for an ESI ID fails the TDSP's internal validation procedures, the TDSP may, at its discretion, delay sending consumption information for the ESI ID to ERCOT for an additional seven days in order to obtain a valid meter reading.

(3) If a TDSP is unable to obtain a meter reading for an ESI ID because the TDSP is denied access to the meter, the TDSP may, at its discretion, delay sending consumption information for the ESI ID to ERCOT for an additional seven days in order to obtain a valid meter reading.

(4) A TDSP, with notification to the market, may suspend the transmission of monthly consumption information during periods of storm restoration or other emergency operations undertaken pursuant to its emergency operations plan.

(5) For non-ERCOT ESI IDs, TDSPs shall have the option of sending monthly consumption information and effectuating meter reads to ERCOT using the 867_03 transaction. ERCOT will then forward the monthly consumption and meter read information to the CR DUNS Number provided in the 867_03 transaction by the TDSP within one Retail Business Day.

15.4 Electric Service Identifier

(1) Each Transmission and/or Distribution Service Provider (TDSP) Service Delivery Point shall have a unique number within Texas. Once this unique number has been created and assigned to a Service Delivery Point, it shall not be re-issued, even in the event of termination of the associated point-of-service. This unique number shall be referred to as the Electric Service Identifier (ESI ID).

(2) Notwithstanding the foregoing, in those situations where an ESI ID has been inadvertently placed into inactive status and upon notification from the responsible TDSP, ERCOT shall re-instate the ESI ID for that Service Delivery Point.

15.4.1 Electric Service Identifier Format

(1) The ESI ID will have the following format:

10xxxxxyyy..yy

Where:

10	Represents a placeholder for future use;
xxxxx	Is the five-digit Department of Energy identification code for the assigning TDSP; and
yyy..yy	Is up to 29 alphanumeric characters assigned by the TDSP.

(2) Allowable alphanumeric characters are 0-9 and A-Z. The total length of the ESI ID cannot exceed 36 alphanumeric characters.

(3) It is the TDSP's responsibility to create, assign, maintain and retire, as necessary, an ESI ID to each Service Delivery Point in its service area.

15.4.1.1 Assignment of ESI IDs to Unmetered Service Delivery Points

(1) In general, each unmetered Service Delivery Point will be assigned an ESI ID corresponding to the point of delivery from the TDSP system to the Customer or Load. The TDSP may, however, aggregate unmetered Service Delivery Points into one ESI ID provided they meet all of the following conditions:

(a) The Service Delivery Points are owned by the same Customer and are located at the same physical location (an exception is allowed for governmental unmetered loads such as street lighting and traffic signals);

(b) All Service Delivery Points have the same Usage Profile;

(c) All Service Delivery Points have the same voltage and are located in the same Unaccounted for Energy (UFE) zone and same Load Zone; and

(d) The TDSP's tariffs allow aggregation of unmetered Service Delivery Points.

15.4.1.2 Assignment of ESI IDs to metered Service Delivery Points

(1) In general, each metered Service Delivery Point will be assigned an ESI ID corresponding to an existing billing meter. However, the TDSP may aggregate metered Service Delivery Points into one ESI ID provided they meet all the following conditions:

(a) The Service Delivery Points are owned by the same Customer and are at the same Service Address;

(b) All Service Delivery Points have the same Load Profile or all Service Delivery Points have Interval Data Recorders (IDRs);

(c) All Service Delivery Points have the same voltage and are located in the same UFE zone and same Load Zone; and

(d) The TDSP's tariffs allow aggregation of separately metered Service Delivery Points.

(2) A Customer may request that the TDSP assign separate ESI IDs for separate Service Delivery Points as allowed in the TDSP's tariffs.

(3) A TDSP may not assign an ESI ID to submeters where the energy consumption for those meters is included in another ESI ID. This does not prohibit the TDSP from tracking these submeters internally or charging for submetering services via the Competitive Retailer (CR). Notwithstanding the foregoing, TDSPs using the practice of subtract metering shall assign an ESI ID to both the master meter and the subtract meter and report adjusted consumption accordingly.

15.4.1.3 Splitting a Service Delivery Point into Multiple ESI IDs

(1) A Service Delivery Point with Load above one MW may split the actual meter into up to four virtual meters which would each have its own ESI ID. This process of splitting the meter into separate ESI IDs shall be performed in accordance with the requirements of Section 10, Metering. Reissuing and reassignment of ESI IDs is prohibited.

15.4.1.4 New Electric Service Identifier Creation

(1) Since it is anticipated that the ESI ID will be based on the existing TDSP account or Premise numbers (with a prefix identifying the TDSP), the TDSP will assign and submit to the registration database ESI IDs for new Premises as service is extended to them. TDSPs that opt in after the market startup will be responsible for the creation of ESI IDs for all existing Service Delivery Points in their service territory.

(2) The TDSP will send ESI ID information using the 814_20, ESI ID Maintenance Request. ERCOT will verify that this transaction meets Texas Standard Electronic Transaction (TX SET) specifications. ERCOT will respond to the TDSP within one Retail Business Hour, with acceptance or rejection of these transactions using the 814_21, ESI ID Maintenance Response. At least the following data elements are required to be sent in the 814_20 transaction:

(a) ESI ID;

(b) Service Address; city, state, zip;

[NPRR1095: Replace paragraph (b) above with the following upon system implementation:]

(b) Service Address; city, state, zip, county;

(c) Load Profile Type;

(d) Meter reading cycle or meter cycle by day of month;

(e) Station ID;

(f) Distribution Loss Factor (DLF) code; and

(g) Premise type.

(3) The TDSP must receive an accepted 814_21 from ERCOT prior to initiating electric service pursuant to Section 15.1.4, Beginning Service (New Construction Completed and Move Ins).

15.4.1.5 Electric Service Identifier Maintenance

(1) The TDSP will notify ERCOT of any changes in information related to an ESI ID for which it is responsible. The TDSP will send changes to ERCOT using the 814_20, ESI ID Maintenance Request. ERCOT will respond to the TDSP within four Retail Business Hours, using the 814_21, ESI ID Maintenance Response. In addition, ERCOT will send all affected CRs notice of the changes using the 814_20 transaction. The TDSP is responsible for the following data elements:

(a) Service Address; city, state, zip;

[NPRR1095: Replace paragraph (a) above with the following upon system implementation:]

(b) Service Address; city, state, zip, county;

(b) Load Profile Type;

(c) Meter reading cycle or meter cycle by day of month;

(d) Station ID;

(e) DLF code;

(f) Eligibility date;

(g) Meter type;

(h) Rate class and sub-class, if applicable;

(i) Special needs indicator;

(j) Meter type, identification number, number of dials and role for each meter at the ESI ID, if ESI ID is metered;

(k) For unmetered ESI IDs, number and description of each unmetered device;

(l) Premise type;

(m) Advanced Metering System (AMS) or Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ IDR indicator; and

(n) Switch hold indicator.

[NPRR1095: Insert paragraph (o) below upon system implementation:]

(o) Metered service type.

(2) If the 814_20 transaction is invalid, ERCOT will respond to the TDSP using the 814_21 transaction within four Retail Business Hours of receipt of the 814_20, with the exception of an 814_20 transaction that is invalid because of “ESI ID Invalid or Not Found.” In the case of “ESI ID Invalid or Not Found,” ERCOT will hold the 814_20 transaction and continue to retry the request at regular intervals for 48 hours counting only hours on Retail Business Days, but not only Business Hours. If the request remains invalid for 48 hours, the process will terminate and ERCOT will forward an 814_21 transaction.

ERCOT Nodal Protocols

Section 16: Registration and Qualification of Market Participants

December 1, 2022

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16 REGISTRATION AND QUALIFICATION OF MARKET PARTICIPANTS

16.1 Registration and Execution of Agreements

(1) ERCOT shall require each Market Participant to register and execute the Standard Form Market Participant Agreement and, as applicable, Standard Form Reliability Must-Run Agreement, and Standard Form Black Start Agreement.

(2) A Standard Form Market Participant Agreement is in Section 22, Attachments, and ERCOT shall also post this agreement on the ERCOT website.

(3) ERCOT shall post on the ERCOT website all registration procedures and applications necessary to complete registration for any function described in these Protocols. As part of its registration procedures, ERCOT may require one or more of the following:

(a) Reasonable tests of the ability of a Market Participant to communicate with ERCOT or perform as required under these Protocols;

(b) An application fee as determined by the ERCOT Board;

(c) Related agreements for specific purposes (such as agency designation, meter splitting, or network interconnection) that apply only to some Market Participants; and

(d) A representation to ERCOT that no officer, owner, partner or other equity interest owner of the Entity was CEO or President or collectively held more than a 10% equity interest in (as owner, partner or other equity interest owner) another Entity at the time of a default where the default resulted in amounts owed to ERCOT remaining unpaid on any Agreement with ERCOT.

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 Competitive Retailer (CR) pursuant to Section 15.1.3.

16.1.2 Principal of a Market Participant

(1) For purposes of Section 16, Registration and Qualification of Market Participants, a Principal is any of the following, as related to a registered Market Participant or Market Participant applicant:

(a) A sole proprietor of a sole proprietorship;

(b) A general partner of a general partnership;

(c) An executive of a company (e.g., president, chief executive officer, chief operating officer, chief financial officer, general counsel, or equivalent position);

(d) A manager, managing member, or a member vested with the management authority of a limited liability company or limited liability partnership;

(e) A shareholder with more than 10% equity of the Entity; or

(f) A person that has authority to make decisions under these Protocols on behalf of the registered Market Participant or applicant, and is not otherwise controlled by any of the other Principal types listed above, or as otherwise identified by ERCOT.

16.2 Registration and Qualification of Qualified Scheduling Entities

16.2.1 Criteria for Qualification as a Qualified Scheduling Entity

(1) To become and remain a Qualified Scheduling Entity (QSE), an Entity must meet the following requirements:

(a) Submit a properly completed QSE application for qualification, including any applicable fee, necessary disclosures, and designation of Authorized Representatives, each of whom is responsible for administrative communications with the QSE and each of whom has enough authority to commit and bind the QSE and the Entities it represents;

(b) Sign a Standard Form Market Participant Agreement;

(c) Sign any required Agreements relating to use of the ERCOT network, software, and systems;

(d) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of performing the functions of a QSE;

(e) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of complying with the requirements of all ERCOT Protocols and Operating Guides;

(f) Satisfy ERCOT's creditworthiness and capitalization requirements as set forth in this Section, unless exempted from these requirements by Section 16.17, Exemption for Qualified Scheduling Entities Participating Only in Emergency Response Service;

(g) Be generally able to pay its debts as they come due. ERCOT may request evidence of compliance with this qualification only if ERCOT reasonably believes that a QSE is failing to comply with it;

(h) Provide all necessary bank account information and arrange for Fedwire system transfers for two-way confirmation;

(i) Be financially responsible for payment of Settlement charges for those Entities it represents under these Protocols;

(j) Comply with the backup plan requirements in the Operating Guides;

(k) Maintain a 24-hour, seven-day-per-week scheduling center with qualified personnel for the purposes of communicating with ERCOT relating to Day-Ahead and Operating Day exchange of market and operational obligations in representing Load, Resources, and market positions. Those personnel must be responsible for operational communications and must have sufficient authority to commit and bind the QSE and the Entities that it represents. This requirement applies to QSE Level 2, 3, and 4, as defined in Section 2.1, Definitions;

(l) Maintain a scheduling center for the hours of 0900 to 1700 Central Prevailing Time (CPT) on Business Days with qualified personnel for the purposes of communicating with ERCOT relating to Day-Ahead and Operating Day exchange of market and operational obligations in representing Load, Resources, and market positions. Those personnel must be responsible for operational communications and must have sufficient authority to commit and bind the QSE and the Entities that it represents. This requirement applies to QSE Level 1, as defined in Section 2.1;

(m) Demonstrate and maintain a working functional interface with all required ERCOT computer systems; and

(n) Allow ERCOT, upon reasonable notice, to conduct a site visit to verify information provided by the QSE.

(2) If a QSE chooses to use Electronic Data Interchange (EDI) transactions to receive Settlement Statements and Invoices, it must participate in and successfully complete testing as described in Section 19.8, Retail Market Testing, before starting operations with ERCOT as a QSE.

(3) A QSE or QSE applicant must be able to demonstrate to ERCOT's reasonable satisfaction that none of its Principals were or are Principals of any Entity with an outstanding payment obligation that remains owing to ERCOT under any Agreement or

these Protocols. For purposes of this Section, ERCOT will only consider disqualifying those Principals of the QSE or QSE applicant who were Principals of the other Entity at a time during which the unpaid financial obligation remained owing to ERCOT or during the 120-day period prior to the date on which the unpaid financial obligation first became due and owing to ERCOT.

(4) If any of a QSE's or QSE applicant's Principals were or are Principals of a terminated Market Participant with an obligation for Default Uplift Ratio Share allocated under Section 9.19.1, Default Uplift Invoices, the terminated Market Participant must be current on all payment obligations for Default Uplift Invoices in order for the QSE to remain, or QSE applicant to become, a registered QSE. For purposes of this Section, ERCOT will only consider as disqualifying those Principals of the QSE or QSE applicant who were Principals of the other Entity at a time during which the other Entity was not current on its payment obligation for Default Uplift Invoices or 120 days prior to the date the other Entity first failed to pay a Default Uplift Invoice.

(5) A QSE shall promptly notify ERCOT of any change that a reasonable examiner may deem material to the QSE's ability to continue to meet the requirements set forth in this Section, and any material change in the information provided by the QSE to ERCOT that may adversely affect the reliability or safety of the ERCOT System or the financial security of ERCOT. This includes any changes in the Principals of the QSE. If the QSE fails to so notify ERCOT of such change within two Business Days after becoming aware of the change, then ERCOT may, after providing notice to each Entity represented by the QSE, refuse to allow the QSE to perform as a QSE and take any other action ERCOT deems appropriate, in its sole discretion, to prevent ERCOT or Market Participants from bearing potential or actual risks, financial or otherwise, arising from those changes, and in accordance with these Protocols.

(6) Subject to the following provisions of this paragraph, a QSE may partition itself into any number of subordinate QSEs ("Subordinate QSEs"). If a single Entity requests to partition itself into more than four Subordinate QSEs, ERCOT may implement the request subject to ERCOT's reasonable determination that the additional requested Subordinate QSEs will not be likely to overburden ERCOT's staffing or systems. ERCOT shall adopt an implementation plan allowing phased-in registration for these additional Subordinate QSEs in order to mitigate system or staffing impacts. However, ERCOT may not unreasonably delay that registration.

(7) Each Subordinate QSE must be treated as an individual QSE for all purposes including communications and control functions except for liability, financial security, and financial liability requirements under this Section. That liability, financial security, and financial liability is cumulative for all Subordinate QSEs for the single Entity signing the QSE Agreement.

(8) Continued qualification as a QSE is contingent upon compliance with all applicable requirements in these Protocols. ERCOT may suspend a QSE's rights as a Market Participant when ERCOT reasonably determines that it is an appropriate remedy for the Entity's failure to satisfy any applicable requirement.

(9) Each QSE, or its designated QSE agent, representing one or more Resources shall be connected to the ERCOT Wide Area Network (WAN) and maintain 24-hour, seven-day-per-week operations and Hotline communications with ERCOT. Each QSE representing one or more Resources shall answer each QSE Hotline call.

16.2.1.1 Data Agent-Only Qualified Scheduling Entities

(1) An Entity may request registration as a Data Agent-Only QSE by submitting a completed Data Agent-Only QSE application. ERCOT will consider the application and register the Entity as a Data Agent-Only QSE in accordance with the same processes in Section 16.2, Registration and Qualification of Qualified Scheduling Entities, generally applicable to the QSE application process.

(2) An Entity is eligible to register as a Data Agent-Only QSE and maintain that registration if it:

(a) Meets all the eligibility criteria to qualify as a QSE under paragraph (1) of Section 16.2.1, Criteria for Qualification as a Qualified Scheduling Entity, except for items (f), (h), (j), and (k);

(b) Is not also registered as a Congestion Revenue Right (CRR) Account Holder;

(c) Does not participate in the Day-Ahead Market (DAM) or Real-Time Market (RTM);

(d) Does not participate in the Emergency Response Service (ERS) market;

(e) Does not have decision making authority over the Resources for which the Entity provides agency services;

(f) Maintains a 24-hour, seven-day-per-week support contact with qualified personnel to support and resolve any data or communication issues with ERCOT. This requirement applies to QSE Level 2, 3, and 4 as defined in Section 2.1, Definitions; and

(g) Maintains a scheduling center for the hours of 0900 to 1700 CPT on Business Days with qualified personnel to support and resolve any data or communication issues with ERCOT. This requirement applies to QSE Level 1, as defined in Section 2.1.

(3) A registered Data Agent-Only QSE may only be appointed to act as the authorized agent of a QSE that meets all requirements of Section 16.2.1 for the limited purpose of exchanging or communicating certain types of data with ERCOT provided that a QSE Agency Agreement making such appointment has been properly executed by the parties and accepted by ERCOT. If a Data Agent-Only QSE is appointed as such an agent, it shall perform its agency services in accordance with the terms of the QSE Agency Agreement and the requirements for WAN Participants under the Nodal Operating Guide

Section 7, Telemetry and Communication. Once a Data Agent-Only QSE has been designated as an agent as provided herein, it will be authorized to act on behalf of the designating QSE and the Market Participant represented by the designating QSE.

(4) A Data Agent-Only QSE shall comply with the obligations applicable to QSEs under this Section 16, Registration and Qualification of Market Participants, but is exempt from the following requirements:

(a) Paragraph (1)(f) of Section 16.2.1;

(b) Paragraph (1)(h) of Section 16.2.1;

(c) Paragraph (1)(j) of Section 16.2.1;

(d) Paragraph (1)(k) of Section 16.2.1;

(e) Section 16.11, Financial Security for Counter-Parties; and

(f) Section 16.16, Additional Counter-Party Qualification Requirements.

(5) ERCOT will ensure that its systems prevent participation by a Data Agent-Only QSE in the DAM and RTM.

(6) A Data Agent-Only QSE may request to change its registration to a QSE that meets all the requirements of Section 16.2.1 and is registered with ERCOT as such by submitting a written request to ERCOT. ERCOT will change the Data Agent-Only QSE’s registration upon satisfaction of all requirements in Section 16.2.1.

(7) Nothing in this Section affects a Data Agent-Only QSE’s obligation under paragraph (5) of Section 16.2.1 to provide ERCOT notice of any material change that could adversely affect the reliability or safety of the ERCOT System.

(8) Each Data Agent-Only QSE representing a QSE that represents one or more Resources shall be connected to the ERCOT WAN and maintain 24-hour, seven-day-per-week operations and Hotline communications with ERCOT. Each Data Agent-Only QSE representing a QSE that represents one or more Resources shall answer each QSE Hotline call.

16.2.2 QSE Application Process

(1) To register as a QSE, an applicant must submit to ERCOT a completed Section 23, Form G, QSE Application and Service Filing for Registration Form, and any applicable fee. ERCOT shall post on the ERCOT website the form in which QSE applications must be submitted, all materials that must be provided with the QSE application and the fee schedule, if any, applicable to QSE applications. The QSE application shall be attested to by a duly authorized officer or agent of the applicant. The QSE applicant shall promptly notify ERCOT of any material changes affecting a pending application using the

appropriate form posted on the ERCOT website. The application must be submitted at least 60 days before the proposed date of commencement of service.

16.2.2.1 Notice of Receipt of Qualified Scheduling Entity Application

(1) Within three Business Days after receiving a QSE application, ERCOT shall issue to the applicant a written confirmation that ERCOT has received the QSE application. ERCOT shall return without review any QSE application that does not include the proper application fee. The remainder of this Section does not apply to any QSE application returned for failure to include the proper application fee.

16.2.2.2 Incomplete QSE Applications

(1) Within ten Business Days after receiving a QSE application, ERCOT shall notify the applicant in writing if the application is incomplete. An application will not be deemed complete until ERCOT has received all information necessary to conduct an evaluation of whether the applicant satisfies the requirements to be registered as a QSE.

(2) If a QSE application is incomplete, ERCOT's notice of incompletion to the applicant must explain the deficiencies and describe the additional information necessary to make the QSE application complete. The QSE applicant has five Business Days after it receives the notice, or a longer period if ERCOT allows, to provide the additional required information.

(3) If the applicant does not respond to the incompletion notice within the time allotted, ERCOT shall reject the application and shall notify the applicant using the procedures below.

(4) ERCOT will notify the applicant of the date on which the application is deemed complete.

16.2.2.3 ERCOT Approval or Rejection of Qualified Scheduling Entity Application

(1) ERCOT will approve or reject a QSE application within 60 days after the application has been deemed complete as provided for in Section 16.2.2.2, Incomplete QSE Applications, unless ERCOT determines that additional time is needed to complete its review of the application. ERCOT will notify the applicant when additional time is needed to complete its review and will provide a date by which ERCOT expects to complete its review. If ERCOT's initial evaluation indicates that there may be a basis to reject the application, ERCOT may contact the applicant prior to rendering a final decision on the application to determine if further information can be provided by the applicant to resolve the identified concern.

(2) If ERCOT rejects a QSE application, ERCOT shall send the applicant a rejection letter explaining the grounds upon which ERCOT rejected the QSE application. Appropriate grounds for rejecting a QSE application include the following:

(a) Required information is not provided to ERCOT in the allotted time;

(b) Noncompliance with technical requirements; and

(c) Noncompliance with other specific eligibility requirements in this Section or in any other Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the QSE applicant may challenge the rejection of its QSE application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new QSE application and fee at any time, and ERCOT shall process the new QSE application under this Section.

(4) If ERCOT approves the QSE application, ERCOT shall send the applicant a Standard Form Market Participant Agreement and any other required Agreements relating to use of the ERCOT network, software, and systems for the applicant's signature.

(5) If ERCOT fails to approve or deny the QSE application within 60 days after the application is deemed complete, and also fails to notify the applicant that additional time is needed to complete its review, the QSE applicant may seek relief using the dispute resolution procedures set forth in Section 20.

16.2.3 Remaining Steps for Qualified Scheduling Entity Registration

(1) After a QSE application is deemed approved under Section 16.2.2.3, ERCOT Approval or Rejection of Qualified Scheduling Entity Application, the applicant shall coordinate or perform the following:

(a) Return the signed Standard Form Market Participant Agreement and other related agreements to ERCOT;

(b) Coordinate with ERCOT and other Entities, as necessary, to test all communications necessary to participate in the market in the ERCOT Region;

(c) If applicable, a QSE offering services in a Non-Opt-In Entity (NOIE) service territory must obtain written authorization from the NOIE, and submit such authorization to ERCOT; and

[PIR005: ERCOT Protocol Interpretation of paragraph (1)(c) of Section 16.2.3 above:]

On June 29, 2021, ERCOT issued a Protocol Interpretation regarding the applicability of paragraph (1)(c) of Section 16.2.3 to QSEs representing Energy Storage Resources. See Market Notice M-A062921-01, Protocol Interpretation Regarding Necessity of Non-Opt-In Entity

Consent to Qualified Scheduling Entity Representation of Energy Storage Resource in Non-Opt-In Entity Service Territory, at http://www.ercot.com/mktrules/nprotocols/pir_process.html for full details of this Protocol Interpretation.

(d) Demonstrate compliance with security and financial requirements.

16.2.3.1 Process to Gain Approval to Follow DSR Load

(1) Each QSE wanting to use Resources to follow Dynamically Scheduled Resource (DSR) Load shall submit a proposal to ERCOT for analysis of the feasibility and reliability of the telemetry required by the proposal. ERCOT shall either approve or disapprove that proposal based on ERCOT's ability to monitor the DSR Load behavior.

(2) Each DSR Load must be associated with a Load meter or group of Load meters. This includes Load that is calculated by subtracting interchange telemetry from actual generation telemetry, appropriately adjusted for Transmission and Distribution Losses.

[NPRR1000: Delete Section 16.2.3.1 above upon system implementation and renumber accordingly.]

16.2.3.2 Maintaining and Updating QSE Information

(1) Each QSE must timely update information the QSE provided to ERCOT in the application process, and a QSE must promptly respond to any reasonable request by ERCOT for updated information regarding the QSE or the information provided to ERCOT by the QSE, including:

(a) The QSE's addresses;

(b) A list of Principals, as defined in Section 16.1.2, Principal of a Market Participant;

(c) A list of Affiliates; and

(d) Designation of the QSE's officers, directors, Authorized Representatives, Credit Contacts, and User Security Administrator (USA) (all per the QSE application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

16.2.3.3 Qualified Scheduling Entity Service Termination

(1) If a QSE intends to terminate representation of a Load Serving Entity (LSE) or Resource (other than an LSE or Resource serving as its own QSE, in which case this Section does

not apply), the QSE shall provide, no less than 12 Business Days before the specified effective termination date ("Termination Date"), written notice to ERCOT and the LSE or Resource.

(2) Effective at 2400 on the Termination Date specified by the QSE, the QSE may no longer provide QSE services for or represent the terminated LSE or Resource. The QSE is responsible for settlement obligations that the QSE has incurred on behalf of the terminated LSE or Resource before the termination. The QSE must participate in Real-Time Operations through the Termination Date and provide updates pursuant to these Protocols for the Operating Day which is the Termination Date. Notwithstanding the foregoing, if, before the Termination Date, the LSE/Resource:

(a) Affiliates itself with a new QSE, or

(b) Fulfills ERCOT's creditworthiness requirements in order to become an Emergency QSE,

the QSE that provided notice of the intent to terminate representation of the LSE/ Resource will no longer be responsible for the terminated LSE/Resource upon the effective date of the new QSE's representation of that LSE/Resource, or the LSE/Resource qualifying as an Emergency QSE.

(3) Within two Business Days of notice of a QSE's intent to terminate representation of an LSE, ERCOT shall notify the LSE of the level of credit the LSE must provide, if it becomes an Emergency QSE, and the date by which it must post the required collateral.

16.2.4 Posting of Qualified Scheduling Entity List

(1) ERCOT shall post on the ERCOT website and maintain a current list of all QSEs. ERCOT shall include with that posting a cautionary statement that inclusion on that list does not necessarily mean that a QSE is entitled to provide any service to a third party, nor does it obligate a QSE to provide any service to a third party.

16.2.5 Suspended or Terminated Qualified Scheduling Entity – Notification to LSEs and Resource Entities Represented

(1) If ERCOT suspends a QSE or terminates the QSE's Standard Form Market Participant Agreement for Default, ERCOT shall notify the affected LSEs and Resource Entities that the QSE has been suspended or terminated and the effective date of such suspension or termination.

(2) If an LSE or Resource Entity represented by a terminated or suspended QSE is the same Entity as the terminated or suspended QSE, the provisions of Section 16.11.6.1.6, Revocation of a Market Participant's Rights and Termination of Agreements, shall apply to that LSE or Resource Entity, and that LSE or Resource Entity shall not be entitled to become an Emergency QSE.

16.2.6 Emergency Qualified Scheduling Entity

16.2.6.1 Designation as an Emergency Qualified Scheduling Entity or Virtual Qualified Scheduling Entity

(1) A “Virtual QSE” is defined as an LSE or Resource Entity that has not qualified and been designated as an Emergency QSE, but has been designated by ERCOT to temporarily perform the responsibilities of a QSE.

(2) If a QSE has given Notice of its intent to terminate its relationship with an LSE or Resource Entity, that LSE or Resource Entity, must, by noon on the fourth Business Day after the termination notice date, either:

(a) Designate a new QSE with such relationship to take effect on the Termination Date, or earlier if allowed by ERCOT; or

(b) Satisfy all necessary creditworthiness requirements for QSEs as described in Section 16.2, Registration and Qualification of Qualified Scheduling Entities, and operate as an Emergency QSE as described below.

(3) If ERCOT has given Notice of an LSE’s or Resource Entity’s QSE’s termination or suspension, that LSE or Resource Entity will be designated as a Virtual QSE for up to two Bank Business Days, during which time it must either:

(a) Designate and begin operations with a new QSE; or

(b) Satisfy all necessary creditworthiness requirements for QSEs as described in Section 16.2, and operate as an Emergency QSE as described below. As provided in paragraph (2) of Section 16.2.5, Suspended or Terminated Qualified Scheduling Entity – Notification to LSEs and Resource Entities Represented, this option does not apply to an LSE or Resource Entity represented by a terminated or suspended QSE that is the same Entity as the terminated or suspended QSE.

(4) If an LSE or Resource Entity meets the creditworthiness requirements, the LSE or Resource Entity may be designated as an Emergency QSE except as provided in paragraph (2) of Section 16.2.5 and may, upon the Termination Date, be issued Digital Certificates and given access to the Market Information System (MIS) as determined by ERCOT.

(5) If the LSE fails to meet the requirements of one of the above options in the timeframe set forth above, it shall constitute a QSE Affiliation Breach under the LSE’s Standard Form Market Participant Agreement. If the LSE fails to cure the QSE Affiliation Breach within the cure period set forth in the Standard Form Market Participant Agreement, and the LSE serves Load, ERCOT shall, after notice as specified in Retail Market Guide Section 7.11, Transition Process, initiate a Mass Transition of the LSE’s Electronic Service Identifiers (ESI IDs) pursuant to Section 15.1.3, Transition Process.

(6) If a Resource Entity fails to meet the requirements of one of the options set forth in paragraph (2) or (3) above within the requisite timeframe, it shall constitute a QSE Affiliation Breach under the Resource Entity's Standard Form Market Participant Agreement, provided that ERCOT may allow the Resource Entity additional time, as determined by ERCOT staff, to meet the requirements.

(7) For any Operating Day in which an LSE or Resource Entity is not either represented by a QSE or qualified as an Emergency QSE, ERCOT may designate the LSE or Resource Entity as a Virtual QSE. ERCOT may issue Digital Certificates to the Virtual QSE for access to the capabilities of the MIS. A Virtual QSE shall be liable for any and all charges associated with Initial, Final and True-Up Settlements as well as any Resettlements applying to dates during which the Virtual QSE represented ESI IDs or otherwise incurred charges pursuant to these Protocols, along with any and all costs incurred by ERCOT in collecting such amounts.

(8) ERCOT shall maintain a referral list of qualified QSEs on the ERCOT website who request to be listed as providing QSE services on short notice. The list shall include the QSE's name, contact information and whether they are qualified to represent Load and/or Resources and/or provide Ancillary Services. ERCOT shall not be obligated to verify the abilities of any QSE so listed. ERCOT shall require all QSEs listed to confirm their inclusion on the referral list no later than the start of each calendar year.

16.2.6.2 Market Participation by an Emergency Qualified Scheduling Entity or a Virtual Qualified Scheduling Entity

(1) An Emergency QSE or a Virtual QSE may only represent itself; it may not represent another legal Entity.

(2) An Emergency QSE or a Virtual QSE that is also an LSE may only submit the following transactions, and may do so only to the extent that the transactions are intended to serve the Load of the Emergency QSE's or Virtual QSE's Customers:

(a) Energy Trades in which the Emergency QSE or the Virtual QSE is the buyer;

(b) Capacity Trades in which the Emergency QSE or the Virtual QSE is the buyer;

(c) Ancillary Service Trades in which the Emergency QSE or the Virtual QSE is the buyer; and

(d) DAM Energy Bids.

(3) An Emergency QSE or a Virtual QSE that is also a Resource Entity may only submit transactions that are directly attributable to and wholly provided by the Resource Entity's Resource(s).

16.2.6.3 Requirement to Obtain New Qualified Scheduling Entity or Qualified

Scheduling Entity Qualification

(1) Within seven Business Days after receiving designation as an Emergency QSE, an Emergency QSE must either:

(a) Designate a QSE that will represent the LSE or Resource Entity to ERCOT; or

(b) Fulfill all QSE registration and qualification requirements. After completing the requirements in item (b), ERCOT may redesignate the Emergency QSE as a QSE.

(2) If an Emergency QSE that is an LSE fails to meet at least one of the requirements listed above within the allotted time, then ERCOT shall, after notice as specified in Retail Market Guide Section 7.11, Transition Process, initiate a Mass Transition of the LSE's ESI IDs pursuant to Section 15.1.3, Transition Process. If an Emergency QSE that is a Resource Entity fails to meet at least one of the requirements listed above within the allotted time, ERCOT may allow the Resource Entity additional time, as determined by ERCOT staff, to meet the requirements.

16.2.7 Acceleration

(1) Upon termination of a QSE's rights as a QSE and the Standard Form Market Participant Agreement or any other Agreement(s) between ERCOT and the QSE, all sums owed to ERCOT are immediately accelerated and are immediately due and owing in full. At that time, ERCOT may immediately draw upon any security or other collateral pledged to ERCOT and may offset or recoup all amounts due to ERCOT to satisfy those due and owing amounts.

16.3 Registration of Load Serving Entities

(1) Load Serving Entities (LSEs) provide electric service to Customers and Wholesale Customers. LSEs include Non-Opt-In Entities (NOIEs) that serve Load, Competitive Retailers (CRs) (which includes Retail Electric Providers (REPs)), and External Load Serving Entities (ELSEs). Each LSE must register with ERCOT. To become registered as an LSE, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate LSE Authorized Representatives, contacts, and a User Security Administrator (USA) (per Section 23, Form B, Load Serving Entity (LSE) Application for Registration), and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of an LSE under these Protocols. Additionally, a REP must demonstrate certification by P.U.C. SUBST. R. 25.107, Certification of Retail Electric Providers (REPs), and comply with the remaining requirements of this Section.

(2) All CRs must participate in and successfully complete testing as described in Section 19.8, Retail Market Testing, prior to commencing operations with ERCOT.

(3) ERCOT may require that the Entity satisfactorily complete testing of interfaces between the Entity's systems and relevant ERCOT systems.

(4) An Entity that wishes to register as an ELSE shall select the ELSE status on the LSE application (Section 23, Form B, Load Serving Entity (LSE) Application for Registration) and other registration forms as designated by ERCOT. An ELSE shall provide all information sufficient to justify its designation as an ELSE if so requested by ERCOT.

(5) An ELSE shall assign an Electric Service Identifier (ESI ID) for each wholesale point of delivery as specified in these Protocols. An ESI ID shall not be assigned to any individual Customer behind an ELSE wholesale point of delivery.

16.3.1 Technical and Managerial Requirements for LSE Applicants

(1) An LSE applicant must:

(a) Be capable of complying with all policies, rules, guidelines, registration requirements and procedures established by these Protocols, ERCOT, or other Independent Organizations, if applicable;

(b) Be capable of purchasing power from Entities registered with or by ERCOT or the Independent Organizations and capable of complying with its system rules; and,

(c) Be capable of purchasing capacity and reserves, or other Ancillary Services, as may be required by ERCOT, or other Independent Organizations, to provide adequate electricity to all the applicant's Customers.

16.3.1.1 Designation of a Qualified Scheduling Entity

(1) Each LSE applicant within the ERCOT Region shall designate the Qualified Scheduling Entity (QSE) that will perform QSE functions per these Protocols on behalf of the LSE. Each applicant shall acknowledge that it bears sole responsibility for selecting and maintaining a QSE as its representative. The applicant shall include a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the applicant's transactions under these Protocols (Section 23, Form B, Attachment A). The acknowledgement of the LSE's QSE designation must be approved by ERCOT prior to a CR's enrollment of Customer ESI IDs or prior to NOIE or ELSE registration of a wholesale point of delivery.

(2) If an LSE fails to maintain a QSE as its representative, the LSE may be designated as an Emergency QSE as provided in Section 16.2.6.1, Designation as an Emergency Qualified Scheduling Entity or Virtual Qualified Scheduling Entity.

16.3.2 Registration Process for Load Serving Entities

(1) Any Entity providing electric service to Customers in ERCOT, or in Non-ERCOT portions of Texas in areas where Customer Choice is in effect, must submit to ERCOT an LSE application (Section 23, Form B, Load Serving Entity (LSE) Application for Registration). ERCOT shall post on the ERCOT website the form in which LSE applications must be submitted, all materials that must be provided with the LSE application, and the fee schedule, if any, applicable to LSE applications.

(2) The LSE application must be attested to by a duly authorized officer or agent of the applicant. The applicant shall promptly notify ERCOT of any material changes affecting a pending LSE application using the appropriate form posted on the ERCOT website.

16.3.2.1 Notice of Receipt of Load Serving Entity Application

(1) Within three Business Days after receiving an LSE application, ERCOT shall issue the LSE applicant a written confirmation that ERCOT has received the LSE application. ERCOT shall return without review any LSE application that does not include the proper application fee. The remainder of this Section does not apply to any LSE application returned for failure to include the proper application fee.

16.3.2.2 Incomplete Load Serving Entity Applications

(1) Not more than ten Business Days after receiving an LSE application, ERCOT shall notify the applicant in writing whether the application is complete.

(2) If ERCOT determines that an LSE application is not complete, ERCOT's notice must explain the reasons for that determination and the additional information necessary to make the application complete. The applicant has five Business Days from receiving ERCOT's notice, or such longer period as ERCOT may allow, to provide the additional information set forth in ERCOT's notice. If the applicant timely responds to ERCOT's notice with the required additional information, then the application is deemed complete on the date that ERCOT receives the applicant's response.

(3) If the applicant does not timely respond to ERCOT's Notice, then the application must be rejected, and ERCOT shall retain any application fee included with the application.

16.3.2.3 ERCOT Approval or Rejection of Load Serving Entity Application

(1) ERCOT may reject an LSE application within ten Business Days after the application has been deemed complete in accordance with this Section. If ERCOT does not reject the LSE application within ten Business Days after the application is deemed complete then the application is deemed approved.

(2) If ERCOT rejects a LSE application, ERCOT shall send the LSE applicant a rejection letter explaining the grounds upon which ERCOT rejected the LSE application. Appropriate grounds for rejecting a LSE application include the following:

(a) Required information is not provided to ERCOT in the allotted time;

(b) Noncompliance with technical requirements; and

(c) Noncompliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the LSE applicant may challenge the rejection of its LSE application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new LSE application and fee at any time, and ERCOT shall process the new LSE application under this Section.

16.3.3 Changing QSE Designation

(1) An LSE may change its designation of QSE with written notice to ERCOT no more than once in any consecutive three days.

(2) If an LSE's representation by a QSE will terminate or the LSE intends to be represented by a different QSE, the LSE shall provide the name of the newly designated QSE to ERCOT along with a written statement from the designated QSE acknowledging the QSE's agreement to accept responsibility for the LSE's transactions under these Protocols. ERCOT shall notify the LSE of approval or disapproval as soon as practicable after receipt of the designation.

(3) The LSE shall submit updated QSE designation information to ERCOT no less than six days prior to the effective date.

(4) Within two days of approving the LSE's notice, ERCOT shall notify all affected Entities, including the LSE's current QSE, of the effective date of the change.

16.3.4 Maintaining and Updating LSE Information

(1) Each LSE must timely update information the LSE provided to ERCOT in the application process, and an LSE must promptly respond to any reasonable request by ERCOT for updated information regarding the LSE or the information provided to ERCOT by the LSE, including:

(a) The LSE's addresses;

(b) A list of Affiliates; and

(c) Designation of the LSE's officers, directors, Authorized Representatives, and User Security Administrator (all per the LSE application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

16.4 Registration of Transmission and Distribution Service Providers

(1) Each Entity operating as a Transmission Service Provider (TSP) or Distribution Service Provider (DSP) within the ERCOT Region, including Municipally Owned Utilities (MOUs) and Electric Cooperatives (ECs), shall register as a TSP or DSP, or both, as applicable, with ERCOT. To register as a TSP or DSP, an Entity must comply with the backup plan requirements in the Operating Guides, execute a Standard Form Market Participant Agreement (using the form provided in Section 22, Attachment A, Standard Form Market Participant Agreement), designate TSP or DSP Authorized Representatives, contacts, and a User Security Administrator (USA) (per Section 23, Form J, Transmission and/or Distribution Service Provider Application for Registration), and be capable of performing the functions of a TSP or DSP, as applicable, as described in these Protocols.

(2) DSPs operating within portions of Texas in areas where Customer Choice is in effect (including opt-in MOUs and opt-in co-ops) must participate in and successfully complete testing as described in Section 19.8, Retail Market Testing, before starting operations with ERCOT.

16.5 Registration of a Resource Entity

(1) A Resource Entity owns or controls a Generation Resource, Settlement Only Generator (SOG), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Generation Resource, SOG, or Load Resource through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. A Resource Entity may submit a proposal to register a SOG consisting of an Energy Storage System (ESS) or a combination of ESS and non-ESS generation. The Resource Entity must identify all components of the SOG as part of the Resource Registration process.

[NPRR995 and NPRR1002: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) A Resource Entity owns or controls a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource, SOG, or SOESS through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. If a Resource Entity intends to register one or more Energy Storage Systems (ESSs) and one or more non-ESS generators as SOGs at the same site, the Resource Entity must provide an affidavit attesting to the amount of ESS and non-ESS capacity at the site as a condition for registration.

(2) Prior to commissioning, Resources Entities will regularly update the data necessary for modeling. These updates will reflect the best available information at the time submitted.

(3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource or SOG meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource or SOG in Exhibit "C" (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2 to assess whether the Generation Resource or SOG, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource or SOG within 90 days of the date the Generation Resource or SOG meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource or SOG violates any operational standards established in the Protocols, Planning Guide, Nodal

Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

[NPRR995 and NPRR1002: Replace applicable portions of paragraph (3) above with the following upon system implementation:]

(3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, ESR, SOG, or SOESS meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, ESR, SOG, or SOESS in Exhibit "C" (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2, to assess whether the Generation Resource, ESR, SOG, or SOESS, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, ESR, SOG, or SOESS within 90 days of the date the Generation Resource, ESR, SOG, or SOESS meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, ESR, SOG, or SOESS violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

(4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, Settlement Only Transmission Generator (SOTG), or Settlement Only Transmission Self-Generator (SOTSG) in the event of any of the following conditions:

(a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, SOTG, or SOTSG may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT's satisfaction that the Generation Resource, SOTG, or SOTSG can comply with these standards;

(b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, SOTG, or SOTSG; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

[NPRR995 and NPRR1002: Replace applicable portions of paragraph (4) above with the following upon system implementation:]

(4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:

(a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT's satisfaction that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS can comply with these standards;

(b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, SOTSG, or SOTESS; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

(5) DG with an installed capacity greater than one MW, the DG registration threshold, which exports energy into a Distribution System, must register with ERCOT.

(6) A Resource Entity representing an Energy Storage Resource (ESR) shall register the ESR as both a Generation Resource and a Controllable Load Resource.

[NPRR1002: Replace paragraph (6) above with the following upon system implementation:]

(6) A Resource Entity representing an ESR shall register the ESR as an ESR. ERCOT systems, including the Energy and Market Management System (EMMS) and Settlement system, shall continue to treat the ESR as both a Generation Resource and a Controllable Load Resource until such time as all ERCOT systems are capable of treating an ESR as a single Resource.

16.5.1 Technical and Managerial Requirements for Resource Entity Applicants

(1) A Resource Entity applicant must:

(a) Be capable of complying with all policies, rules, guidelines, registration requirements, and procedures established by these Protocols, ERCOT, or other Independent Organizations, if applicable; and

(b) Be capable of purchasing power from Entities registered with or by ERCOT or the Independent Organizations and capable of complying with its system rules.

16.5.1.1 Designation of a Qualified Scheduling Entity

(1) Each Resource Entity applicant within the ERCOT Region shall designate the Qualified Scheduling Entity (QSE) that will perform QSE functions per these Protocols on behalf of the Resource Entity. Each applicant shall acknowledge that it bears sole responsibility for selecting and maintaining a QSE as its representative. The applicant shall include a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the applicant's transactions pursuant to these Protocols. For the Resource Entity that owns or operates a Generation Resource, the Resource Entity's QSE designation must be submitted to ERCOT no later than 45 days prior to the Network Operations Model change date, as described in Section 3.10.1, Time Line for Network Operations Model Changes, for the Resource.

(2) If a Resource Entity fails to maintain a QSE as its representative, the Resource Entity may be designated as an Emergency QSE as provided in Section 16.2.6.1, Designation as an Emergency Qualified Scheduling Entity or Virtual Qualified Scheduling Entity.

16.5.1.2 Waiver for Federal Hydroelectric Facilities

(1) ERCOT may grant a waiver to any federally owned hydroelectric Generation Resource, SOG, or Load Resource within the ERCOT System from fulfilling the requirements in Section 16.5, Registration of a Resource Entity, as they pertain to the submission of a Resource Entity application and the execution of a Standard Form Market Participant Agreement (Section 22, Attachment A, Standard Form Market Participant Agreement). ERCOT may grant such waiver after the federally owned hydroelectric Resource Entity provides ERCOT with the following:

(a) All information necessary to meet the Resource Entity registration requirements as provided in this Section;

(b) The designation of a QSE for each Generation Resource, SOG, or Load Resource that it owns or controls; and

(c) Assignment of each Generation Resource's, SOG's, or Load Resource's Electric Service Identifier (ESI ID) to a Load Serving Entity (LSE) serving any Load or net Load, if the Generation Resource, SOG, or Load Resource is net metered and will be connected to the ERCOT System. Such Load, if retail Load, is subject to all applicable rules and procedures, including rules concerning disconnection and

Provider of Last Resort (POLR) service, applicable to other retail points of delivery.

[NPRR995: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT may grant a waiver to any federally owned hydroelectric Generation Resource, SOG, SOESS, or Load Resource within the ERCOT System from fulfilling the requirements in Section 16.5, Registration of a Resource Entity, as they pertain to the submission of a Resource Entity application and the execution of a Standard Form Market Participant Agreement (Section 22, Attachment A, Standard Form Market Participant Agreement). ERCOT may grant such waiver after the federally owned hydroelectric Resource Entity provides ERCOT with the following:

(a) All information necessary to meet the Resource Entity registration requirements as provided in this Section;

(b) The designation of a QSE for each Generation Resource, SOG, SOESS, or Load Resource that it owns or controls; and

(c) Assignment of each Generation Resource's, SOG's, SOESS's, or Load Resource's Electric Service Identifier (ESI ID) to a Load Serving Entity (LSE) serving any Load or net Load, if the Generation Resource, SOG, SOESS, or Load Resource is net metered and will be connected to the ERCOT System. Such Load, if retail Load, is subject to all applicable rules and procedures, including rules concerning disconnection and Provider of Last Resort (POLR) service, applicable to other retail points of delivery.

16.5.1.3 Waiver for Block Load Transfer Resources

(1) ERCOT may grant a waiver to a Resource Entity for a Block Load Transfer (BLT) Resource from fulfilling the requirements in Section 16.5, Registration of a Resource Entity, as they pertain to the submission of a Resource Entity application and the execution of a Standard Form Market Participant Agreement (Section 22, Attachment A, Standard Form Market Participant Agreement). ERCOT may grant such waiver after the Resource Entity for the BLT Resource provides ERCOT with the following:

(a) All applicable information necessary to meet the Resource Entity registration requirements as provided in this Section; and

(b) The designation of a QSE for the BLT Resource.

16.5.2 Registration Process for a Resource Entity

(1) To register as a Resource Entity, an applicant must submit to ERCOT a completed Resource Entity application and any applicable fee. ERCOT shall post on the ERCOT

website the form in which Resource Entity applications must be submitted, all materials that must be provided with the Resource Entity application.

(2) The Resource Entity application must be attested to by a duly authorized officer or agent of the applicant. The applicant shall promptly notify ERCOT of any material changes affecting a pending Resource Entity application using the appropriate form posted on the ERCOT website.

(3) If the Resource Entity intends to own or control a Load Resource located within a Non-Opt-In Entity's (NOIE's) service territory, such applicant must designate the NOIE's QSE, or an alternate QSE authorized by the NOIE. If an alternate QSE is designated, then such QSE representing that Load Resource must first obtain written permission from the NOIE prior to offering any services in the NOIE's service territory. The alternate QSE shall submit the NOIE's written permission to ERCOT at the time of designation.

16.5.2.1 Notice of Receipt of Resource Entity Application

(1) Within three Business Days after receiving a Resource Entity application, ERCOT shall issue the Resource Entity applicant a written confirmation that ERCOT has received the application. ERCOT shall return without review any Resource Entity application that is not complete.

16.5.2.2 Incomplete Resource Entity Applications

(1) Not more than ten Business Days after receiving a Resource Entity application, ERCOT shall notify the applicant in writing whether the application is complete.

(2) If ERCOT determines that a Resource Entity application is not complete, ERCOT's notice must explain the reasons for that determination and the additional information necessary to make the application complete. The applicant has five Business Days from receiving ERCOT's notice, or such longer period as ERCOT may allow, to provide the additional information set forth in ERCOT's notice. If the applicant timely responds to ERCOT's notice with the required additional information, then the application is deemed complete on the date that ERCOT receives the applicant's response.

(3) If the applicant does not timely respond to ERCOT's notice, then the application must be rejected, and ERCOT shall retain any application fee included with the application.

16.5.2.3 ERCOT Approval or Rejection of a Resource Entity Application

(1) ERCOT may reject a Resource Entity application within ten Business Days after the application has been deemed complete in accordance with this Section. If ERCOT does not reject the Resource Entity application within ten Business Days after the application is deemed complete then the application is deemed approved.

(2) If ERCOT rejects a Resource Entity application, ERCOT shall send the Resource Entity applicant a rejection letter explaining the grounds upon which ERCOT rejected the Resource Entity application. Appropriate grounds for rejecting a Resource Entity application include the following:

(a) Required information is not provided to ERCOT in the allotted time;

(b) Noncompliance with technical requirements; and

(c) Noncompliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the Resource Entity applicant may challenge the rejection of its Resource Entity application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new Resource Entity application and fee at any time, and ERCOT shall process the new Resource Entity application under this Section.

16.5.3 Changing QSE Designation

(1) A Resource Entity may change its designation of QSE with written notice to ERCOT, no more than once in any consecutive three days.

(2) If a Resource Entity's representation by a QSE will terminate or the Resource Entity intends to be represented by a different QSE, the Resource Entity shall provide the name of the newly designated QSE to ERCOT along with a written statement from the newly designated QSE acknowledging the QSE's agreement to accept responsibility for the Resource Entity's transactions under these Protocols. For the Resource Entity that owns or operates a Generation Resource, the Resource Entity's QSE designation must be approved by ERCOT before the Resource Entity will be evaluated for compliance with the requirements of paragraph (3) below. ERCOT shall notify the Resource Entity of approval or disapproval as soon as practicable after receipt of the request.

(3) For Resources required by these Protocols to be in the Network Operations Model, the following apply:

(a) The designated QSE shall install all telemetry required of these Protocols for the requesting Resource Entity and schedule point-to-point data verification with ERCOT.

(b) The designated QSE shall submit telemetry data descriptions to ERCOT to meet ERCOT's normal model update process.

(c) The Resource must submit any changes in system topology or telemetry according to Section 3.3.2.1, Information to Be Provided to ERCOT.

(d) The effective date for the newly designated QSE shall be in accordance with Section 3.10.1, Time Line for Network Operations Model Changes.

(e) ERCOT may request the Resource Entity to develop a transition implementation plan to be approved by ERCOT that sets appropriate deadlines for completion of all required data and telemetry verification and cutover testing activities with ERCOT.

(4) For all other Resources, the new QSE designation is to be received no less than six days prior to the effective date.

(5) Within two days of approving a Resource Entity's notice, ERCOT shall notify all affected Entities, including the Resource Entity's current QSE, of the effective date of the change.

16.5.4 Maintaining and Updating Resource Entity Information

(1) Each Resource Entity must timely update information the Resource Entity provided to ERCOT in the application process, and a Resource Entity must promptly respond to any reasonable request by ERCOT for updated information regarding the Resource Entity or the information provided to ERCOT by the Resource Entity, including:

(a) The Resource Entity's addresses;

(b) A list of Affiliates; and

(c) Designation of the Resource Entity's officers, directors, Authorized Representatives, and USA (all per the Resource Entity application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

(2) A Resource Entity that has a Switchable Generation Resource (SWGR) shall submit a report to ERCOT in writing indicating whether or not it has any contractual requirement in a non-ERCOT Control Area during the summer or winter Peak Load Seasons which may cause the identified capacity to not be available to the ERCOT System for the subsequent ten years. The initial communication and subsequent updates to previously reported unavailable capacity shall be filed with ERCOT as soon as possible, but in no event later than ten Business Days after the information is obtained. The communications should reflect the Resource Entity's best estimate of the required information at the time the filing is made. ERCOT shall use the provided data for preparation of the Report on Capacity, Demand and Reserves in the ERCOT Region and other planning purposes.

16.6 Registration of Municipally Owned Utilities and Electric Cooperatives in the ERCOT Region

(1) Each Municipally Owned Utility (MOU) and Electric Cooperative (EC) shall register with ERCOT and sign the Agreements that apply to the functions it performs in the ERCOT Region, regardless of whether planning to be a Non-Opt-In Entity (NOIE) or a Competitive Retailer (CR).

(2) Each MOU and EC that decides to opt in shall register as a CR and notify ERCOT of its intentions six months prior to opting in.

(3) Each MOU and EC shall designate a Qualified Scheduling Entity (QSE) with ERCOT on its behalf.

(4) Each MOU and EC shall assign an Electric Service Identifier (ESI ID) to each NOIE wholesale point of delivery as specified in these Protocols. The ESI IDs must be assigned to a Load Serving Entity (LSE).

16.7 Registration of Renewable Energy Credit Account Holders

(1) Each Entity intending to participate in the Renewable Energy Credit (REC) program shall register with ERCOT and execute a Standard Form Market Participant Agreement (as provided in Section 22, Attachment A, Standard Form Market Participant Agreement) prior to participation in the REC program.

16.8 Registration and Qualification of Congestion Revenue Rights Account Holders

16.8.1 Criteria for Qualification as a CRR Account Holder

(1) To become and remain a Congestion Revenue Right (CRR) Account Holder, an Entity must meet the following requirements:

(a) Submit a properly completed CRR Account Holder application (Section 23, Form A, Congestion Revenue Right (CRR) Account Holder Application for Registration) for qualification, including any applicable fee, any necessary disclosures, and designation of Authorized Representatives, each of whom is responsible for administrative communications with the CRR Account Holder and each of whom has enough authority to commit and bind the CRR Account Holder;

(b) Sign a CRR Account Holder Agreement;

(c) Sign any required Agreements relating to use of the ERCOT network, software, and systems;

(d) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of performing the functions of a CRR Account Holder;

(e) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of complying with the requirements of all ERCOT Protocols and Operating Guides;

(f) Satisfy ERCOT's creditworthiness requirements as set forth in this Section;

(g) Be generally able to pay its debts as they come due; ERCOT may request evidence of compliance with this qualification only if ERCOT reasonably believes that a CRR Account Holder is failing to comply with it;

(h) Provide all necessary bank account information and arrange for Fedwire system transfers for two-way confirmation;

(i) Be financially responsible for payment of its Settlement charges under these Protocols; and

(j) Not be an unbundled Transmission Service Provider (TSP), Distribution Service Provider (DSP), or an ERCOT employee.

(2) A CRR Account Holder or CRR Account Holder applicant must be able to demonstrate to ERCOT's reasonable satisfaction that none of its Principals were or are Principals of any Entity with an outstanding payment obligation that remains owing to ERCOT under any Agreement or these Protocols. For purposes of this Section, ERCOT will only consider disqualifying those Principals of the CRR Account Holder or CRR Account Holder applicant who were Principals of the other Entity at a time during which the unpaid financial obligation remained owing to ERCOT or during the 120-day period prior to the date on which the unpaid financial obligation first became due and owing to ERCOT.

(3) If any of a CRR Account Holder's or CRR Account Holder applicant's Principals were or are Principals of a terminated Market Participant with an obligation for Default Uplift Ratio Share allocated under Section 9.19.1, Default Uplift Invoices, the terminated Market Participant must be current on all payment obligations for Default Uplift Invoices in order for the CRR Account Holder to remain, or CRR Account Holder applicant to become, a registered CRR Account Holder. For purposes of this Section, ERCOT will only consider as disqualifying those Principals of the CRR Account Holder or CRR Account Holder applicant who were Principals of the other Entity at a time during which the other Entity was not current on its payment obligation for Default Uplift Invoices or 120 days prior to the date the other Entity first failed to pay a Default Uplift Invoice.

(4) A CRR Account Holder shall promptly notify ERCOT of any material change that a reasonable examiner could deem material to the CRR Account Holder's ability to continue to meet the requirements set forth in paragraphs (1) to (3) above, and any material change in the information provided by the CRR Account Holder to ERCOT that may adversely affect the financial security of ERCOT. This includes any changes in the Principals of the CRR Account Holder. If the CRR Account Holder fails to so notify

ERCOT of the following within two Business Days after becoming aware of the change, then ERCOT may refuse to allow the CRR Account Holder to continue to perform as a CRR Account Holder and take any other action ERCOT deems appropriate, in its sole discretion, to prevent ERCOT or Market Participants from bearing potential or actual risks, financial or otherwise, arising from those changes, and in accordance with these Protocols.

(5) Continued qualification as a CRR Account Holder is contingent upon compliance with all applicable requirements in these Protocols. ERCOT may suspend a CRR Account Holder's rights as a Market Participant when ERCOT reasonably determines that it is an appropriate remedy for the Entity's failure to satisfy any applicable requirement.

16.8.2 CRR Account Holder Application Process

(1) To register as a CRR Account Holder, an applicant must submit to ERCOT a completed Section 23, Form A, Congestion Revenue Right (CRR) Account Holder Application for Registration, and any applicable fee. ERCOT shall post on the ERCOT website the form in which CRR Account Holder applications must be submitted, all materials that must be provided with the CRR Account Holder application and the fee schedule, if any, applicable to CRR Account Holder applications. The CRR Account Holder application shall be attested to by a duly authorized officer or agent of the applicant. The CRR Account Holder applicant shall promptly notify ERCOT of any material changes affecting a pending application using the appropriate form posted on the ERCOT website. The application must be submitted at least 60 days before the first day of participation in the CRR Auction process or purchase of CRRs.

16.8.2.1 Notice of Receipt of CRR Account Holder Application

(1) Within three Business Days after receiving a CRR Account Holder application, ERCOT shall issue to the applicant a written confirmation that ERCOT has received the CRR Account Holder application. ERCOT shall return without review any CRR Account Holder application that does not include the proper application fee. The remainder of this Section does not apply to any CRR Account Holder application returned for failure to include the proper application fee.

16.8.2.2 Incomplete CRR Account Holder Applications

(1) Within ten Business Days after receiving a CRR Account Holder application, ERCOT shall notify the applicant in writing if the application is incomplete. An application will not be deemed complete until ERCOT has received all information necessary to conduct an evaluation of whether the applicant satisfies the requirements to be registered as a CRR Account Holder.

(2) If a CRR Account Holder application is incomplete, ERCOT's notice of incompletion to the applicant must explain the deficiencies and describe the additional information

necessary to make the CRR Account Holder application complete. The CRR Account Holder applicant has five Business Days after it receives the notice, or a longer period if ERCOT allows, to provide the additional required information.

(3) If the applicant does not respond to the incompletion notice within the time allotted, ERCOT shall reject the application and shall notify the applicant using the procedures below.

(4) ERCOT will notify the applicant of the date on which the application is deemed complete.

16.8.2.3 ERCOT Approval or Rejection of CRR Account Holder Application

(1) ERCOT will approve or reject a CRR Account Holder application within 60 days after the application has been deemed complete as provided for in Section 16.8.2.2, Incomplete CRR Account Holder Applications, unless ERCOT determines that additional time is needed to complete its review of the application. ERCOT will notify the applicant when additional time is needed to complete its review and will provide a date by which ERCOT expects to complete its review. If ERCOT's initial evaluation indicates that there may be a basis to reject the application, ERCOT may contact the applicant prior to rendering a final decision on the application to determine if further information can be provided by the applicant to resolve the identified concern.

(2) If ERCOT rejects a CRR Account Holder application, ERCOT shall send the applicant a rejection letter explaining the grounds upon which ERCOT rejected the CRR Account Holder application. Appropriate grounds for rejecting a CRR Account Holder application include the following:

  (a) Required information is not provided to ERCOT in the allotted time;

  (b) Noncompliance with technical requirements; and

  (c) Noncompliance with other specific eligibility requirements in this Section or in any other Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the CRR Account Holder applicant may challenge the rejection of its CRR Account Holder application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new CRR Account Holder application and fee at any time, and ERCOT shall process the new CRR Account Holder application under this Section.

(4) If ERCOT approves the CRR Account Holder application, ERCOT shall send the applicant a CRR Account Holder Agreement and any other required Agreements relating to use of the ERCOT network, software, and systems for the applicant's signature.

(5) If ERCOT fails to approve or deny the CRR Account Holder application within 60 days after the application is deemed complete, and fails to notify the applicant that additional time is needed to complete its review, the CRR Account Holder may seek relief using the dispute resolution procedures set forth in Section 20.

16.8.3 Remaining Steps for CRR Account Holder Registration

(1) After a CRR Account Holder application is deemed approved under Section 16.8.2.3, ERCOT Approval or Rejection of CRR Account Holder Application, the applicant shall coordinate or perform the following:

(a) Return the signed CRR Account Holder Agreement and other related agreements to ERCOT; and

(b) Demonstrate compliance with security and financial requirements.

16.8.3.1 Maintaining and Updating CRR Account Holder Information

(1) Each CRR Account Holder must timely update information the CRR Account Holder provided to ERCOT in the application process, and a CRR Account Holder must promptly respond to any reasonable request by ERCOT for updated information regarding the CRR Account Holder or the information provided to ERCOT by the CRR Account Holder, including:

(a) The CRR Account Holder’s addresses;

(b) A list of Principals;

(c) A list of Affiliates; and

(d) Designation of the CRR Account Holder’s officers, directors, Authorized Representatives, Credit Contacts, and User Security Administrator (all per the CRR Account Holder application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

16.9 Resources Providing Reliability Must-Run Service

(1) Any Entity providing Reliability Must-Run (RMR) Service must comply with all the requirements to become a Resource Entity under this Section and must sign an RMR Agreement (Section 22, Attachment B, Standard Form Reliability Must-Run Agreement).

16.10 Resources Providing Black Start Service

(1) Any Entity providing Black Start Service must comply with all the requirements to become a Resource Entity under this Section and must sign a Standard Form Black Start Agreement (Section 22, Attachment D, Standard Form Black Start Agreement).

16.11 Financial Security for Counter-Parties

(1) The term "Financial Security" in this Section means the collateral amount posted with ERCOT in any of the forms listed in Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

(2) The term "Secured Collateral" in this Section means the collateral posted by a Counter-Party with ERCOT in the form of an unconditional, irrevocable letter of credit, a surety bond naming ERCOT as the beneficiary, or cash.

[NPRR1112: Delete paragraph (2) above upon system implementation and October 1, 2023, and renumber accordingly.]

(3) The term "Remainder Collateral" in this Section means the Secured Collateral minus Total Potential Exposure Secured (TPES) minus Net Positive Exposure of approved Congestion Revenue Right (CRR) Bilateral Trades minus Available Credit Limit (ACL) locked for CRR Auction, calculated in accordance with paragraph (3) of Section 16.11.4.6.1, Credit Requirements for CRR Auction Participation.

[NPRR1112: Replace paragraph (3) above with the following upon system implementation and October 1, 2023:]

(2) The term "Remainder Collateral" in this Section means the Financial Security minus Total Potential Exposure Secured (TPES) minus Net Positive Exposure of approved Congestion Revenue Right (CRR) Bilateral Trades minus Available Credit Limit (ACL) locked for CRR Auction, calculated in accordance with paragraph (3) of Section 16.11.4.6.1, Credit Requirements for CRR Auction Participation.

16.11.1 ERCOT Creditworthiness Requirements for Counter-Parties

(1) Each Counter-Party shall meet ERCOT's creditworthiness standards as provided in this Section. A Counter-Party must, at all times, maintain its Financial Security at or above the amount of its Total Potential Exposure (TPE) minus its Unsecured Credit Limit. Each Counter-Party shall maintain any required Financial Security in a form acceptable to ERCOT in its sole discretion. If at any time the Counter-Party does not meet ERCOT's creditworthiness requirements, then ERCOT may suspend the Counter-Party's rights under these Protocols until it meets those creditworthiness requirements. ERCOT's failure to suspend the Counter-Party's rights on any particular occasion does

not prevent ERCOT from suspending those rights on any subsequent occasion, including a CRR Account Holder's ability to bid on future CRRs or a Qualified Scheduling Entity's (QSE's) ability to bid in the Day-Ahead Market (DAM).

[NPRR1112: Replace paragraph (1) above with the following upon system implementation and October 1, 2023:]

(1) Each Counter-Party shall meet ERCOT's creditworthiness standards as provided in this Section. A Counter-Party must, at all times, maintain its Financial Security at or above the amount of its Total Potential Exposure (TPE). Each Counter-Party shall maintain any required Financial Security in a form acceptable to ERCOT in its sole discretion. If at any time the Counter-Party does not meet ERCOT's creditworthiness requirements, then ERCOT may suspend the Counter-Party's rights under these Protocols until it meets those creditworthiness requirements. ERCOT's failure to suspend the Counter-Party's rights on any particular occasion does not prevent ERCOT from suspending those rights on any subsequent occasion, including a CRR Account Holder's ability to bid on future CRRs or a Qualified Scheduling Entity's (QSE's) ability to bid in the Day-Ahead Market (DAM).

(2) Notwithstanding the provisions in paragraph (1) above, ERCOT may draw on Financial Security if necessary to pay short-pays of miscellaneous Invoices for Securitization Default Charges or Securitization Uplift Charge Initial Invoices if the respective escrow deposits are insufficient to cover the short-pays.

[NPRR1125: Replace paragraph (2) above with the following upon system implementation of NPRR1103:]

(2) Notwithstanding the provisions in paragraph (1) above, ERCOT may draw on Financial Security if necessary to pay short-pays of Securitization Default Charge Invoices or Securitization Uplift Charge Initial Invoices if the respective escrow deposits are insufficient to cover the short-pays.

16.11.2 Requirements for Setting a Counter-Party's Unsecured Credit Limit

(1) The following terms used throughout this section are defined below:

(a) Times Interest Earnings Ratio (TIER) and Debt Service Coverage (DSC) ratios are as defined in 7 C.F.R § 1710.114 (2011).

(b) Maximum Debt to Total Capitalization Ratio is defined as: Long-term debt (including all current borrowings) / (Total shareholder's equity + Long-term debt).

(c) EBITDA is defined as annual Earnings Before Interest, Depreciation and Amortization.

(d) CMLTD, Current Maturities of Long-Term Debt, is defined as the principal portions of long-term debt payable within the next twelve months.

(2) ERCOT, in its sole discretion, may set an Unsecured Credit Limit, not to exceed $50 million, for a Counter-Party if the Counter-Party meets the following requirements as applicable:

(a) If the Counter-Party is an Electric Cooperative (EC) that is not publicly rated by Standard and Poor's (S&P), Fitch or Moody's credit rating agencies, or has less than $100 million in Tangible Net Worth, and is a Rural Utilities Service (RUS) distribution borrower or power supply borrower as those terms are used in 7 C.F.R. § 1717.656 (2014); then the Unsecured Credit Limit shall be set within the range defined in the following table:

If Counter-Party has	And	And	And	Then
Minimum Equity (Patronage Capital)	Minimum Times Interest Earnings Ratio (TIER)	Minimum Debt Service Coverage (DSC)	Minimum Equity to Assets	Maximum Unsecured Credit Limit as a Percentage of Total Assets minus Total Secured Debt
$25,000,000	1.00	1.00	0.15	0.00% to 5.00%

(i) ERCOT shall apply these standards consistent with 7 C.F.R. § 1717.656 (3).

(ii) ERCOT shall utilize annual financial data only for the assessment for those ECs that fall within the scope of this subsection.

(iii) Unsecured Credit Limits for ECs that are publicly rated by S&P, Fitch or Moody's and that have Tangible Net Worth greater than $100 million will be computed in accordance with item (c) below.

(iv) The amount of Unsecured Credit Limit established within the range in the table above is at the discretion of ERCOT if the stated criteria are met.

(b) If the Counter-Party is a Municipal Owned Utility (MOU) that is not publicly rated by S&P, Fitch or Moody's, or has less than $100 million in Tangible Net Worth, the Unsecured Credit Limit shall be set within the range defined in the following table:

If Counter-Party has	And	And	And	Then
Minimum Equity	Minimum Times Interest Earnings Ratio (TIER)	Minimum Debt Service Coverage (DSC)	Minimum Equity to Assets	Maximum Unsecured Credit Limit as a Percentage of Total Assets minus Total Secured Debt
$25,000,000	1.05	1.00	0.15	0.00% to 5.00%

(i) ERCOT shall utilize annual financial data only for the assessment for those MOUs that fall within the scope of this subsection.

(ii) Unsecured Credit Limits for MOUs that are publicly rated by S&P, Fitch or Moody's and that have Tangible Net Worth greater than $100 million will be computed in accordance with item (c) below.

(iii) The amount of the Unsecured Credit Limit established within the range in the table above is at the discretion of ERCOT if the stated criteria are met.

(c) If the Counter-Party is publicly rated by S&P, Fitch or Moody's and has greater than $100 million in Tangible Net Worth, the Unsecured Credit Limit shall be set with the ranges defined in the following table:

If Counter-Party has		And	Then		
Long-Term or Issuer Rating		Tangible Net Worth greater than	Maximum Unsecured Credit Limit as a percentage of Tangible Net Worth		
Fitch/S&P	Moody's				
AAA	Aaa	$100,000,000	0.00%	to	3.00%
AA+	Aa1	$100,000,000	0.00%	to	2.95%
AA	Aa2	$100,000,000	0.00%	to	2.85%
AA-	Aa3	$100,000,000	0.00%	to	2.70%
A+	A1	$100,000,000	0.00%	to	2.55%
A	A2	$100,000,000	0.00%	to	2.35%
A-	A3	$100,000,000	0.00%	to	2.10%
BBB+	Baa1	$100,000,000	0.00%	to	1.80%
BBB	Baa2	$100,000,000	0.00%	to	1.40%
BBB-	Baa3	$100,000,000	0.00%	to	0.70%

If Counter-Party has		And	Then
Long-Term or Issuer Rating		Tangible Net Worth greater than	Maximum Unsecured Credit Limit as a percentage of Tangible Net Worth
Fitch/S&P	Moody's		
Below BBB-	Below Baa3	$100,000,000	Requires Security

(i) If a Counter-Party's or guarantor's debt is rated by more than one of the referenced rating agencies and all ratings fall within ratings categories which are functional equivalents, ERCOT shall assign an Unsecured Credit Limit or allow a guarantee for amounts within the range for that rating.

(ii) If a Counter-Party's or guarantor's debt is rated by more than one of the referenced ratings agencies and the ratings fall within different rating categories which are not functional equivalents, ERCOT shall assign an Unsecured Credit Limit or allow a guarantee for amounts as follows:

(A) If there are three ratings and two of the three are functional equivalents, within the range where two of the three apply;

(B) If there are three ratings and all three are different, within the range where the average of the three ratings apply (rounded down); and

(C) If there are two ratings and the two are different, within the range of the lower of the two.

(iii) ERCOT shall utilize annual financial data only for the assessment for those ECs and MOUs that fall within the scope of this subsection.

(iv) The amount of the Unsecured Credit Limit established within the range in the table above is at the discretion of ERCOT if the stated criteria are met.

(d) If the Counter-Party is a privately held company that is not publicly rated by S&P, Fitch or Moody's, subject to its providing ERCOT with financial statements as specified in paragraph (1) of Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT, the Unsecured Credit Limit shall be set within the range defined in the following table:

If Counter-Party has	And	And	And	Then
Tangible Net Worth	Minimum Current Ratio	Maximum Debt to Total Capitalization Ratio	Minimum EBITDA to Interest and CMLTD	Maximum Unsecured Credit Limit as a percentage of Tangible Net Worth

$100,000,000	1.0	0.60	2.0	0.00%	to	1.80%

(i) The amount of the Unsecured Credit Limit established within the range in the table above is at the discretion of ERCOT if the stated criteria are met.

(e) ERCOT has the discretion to adjust Unsecured Credit Limits and to reasonably request any Counter-Party or guarantor, if applicable, to provide updated financial information in support of Unsecured Credit Limit calculations.

[NPRR1112: Replace Section 16.11.2 above with the following upon system implementation and October 1, 2023:]

16.11.2 [RESERVED]

16.11.3 Alternative Means of Satisfying ERCOT Creditworthiness Requirements

(1) If a Counter-Party is required to provide Financial Security under these Protocols, then it may do so through one or more of the following means:

(a) Another Entity may give a guarantee to ERCOT, if ERCOT has set an Unsecured Credit Limit for the Entity under Section 16.11.2, Requirements for Setting a Counter-Party’s Unsecured Credit Limit. ERCOT shall value the guarantee based on the guarantor’s Unsecured Credit Limit and other obligations the guarantor has under these Protocols or other contracts with ERCOT.

(i) The guarantee must be given using one of the ERCOT Board-approved standard guarantee forms. No modifications are permitted.

(ii) Guarantees are subject to a limit of $50 million of guarantees per Counter-Party and an overall limit of $50 million per guarantor for all ERCOT Counter-Parties.

(iii) For foreign guarantees, the guarantor must also meet the following standards:

(A) The country of domicile for the foreign guarantor must:

(1) Maintain a sovereign rating greater than or equal to AA with Fitch or S&P or Aa2 with Moody’s;

(2) If the ratings are below those in item (a)(iii)(A)(1) above, but greater than or equal to A with Fitch or S&P or A2 with Moody’s, then the sovereign rating would qualify if the country had a ceiling rating of AAA with Fitch or S&P or Aaa with Moody’s; and

(3) Must have reciprocity agreements with the U.S. regarding enforcement and collection of guarantee agreements.

(B) The foreign guarantor must:

(1) Provide to ERCOT annual audited financial statements, prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP) or International Accounting Standards (IAS) and semi-annual unaudited financial statements;

(2) Provide a guarantee in one of the standard form documents approved by the ERCOT Board of Directors for foreign Entities. No modifications are permitted; and

(3) Provide an opinion letter from a law firm unaffiliated with the Counter-Party or guarantor affirming that the guarantee agreement is enforceable in the U.S. and in the jurisdiction of the corporate guarantor's domicile.

(b) The Counter-Party may give an unconditional, irrevocable letter of credit naming ERCOT as the beneficiary. ERCOT may, in its sole discretion, reject the letter of credit if the issuer is unacceptable to ERCOT or if the conditions under which ERCOT may draw against the letter of credit are unacceptable to ERCOT.

(i) The letter of credit must be given using the ERCOT Board-approved standard letter of credit form.

(ii) Letters of credit must be issued by a bank or other financial institution that is acceptable to ERCOT, with a minimum rating of A- with S&P or Fitch or A3 with Moody's.

(iii) Letters of credit are subject to an overall limit per letter of credit issuer for all ERCOT Counter-Parties as determined below:

If the issuing entity has		Then
Long-Term or Issuer Rating		Maximum letter of credit issuer limit as a percentage of Tangible Net Worth of issuer
S&P or Fitch	Moody's	
AAA	Aaa	1.00%
AA+	Aa1	0.95%
AA	Aa2	0.90%
AA-	Aa3	0.85%

If the issuing entity has		Then
Long-Term or Issuer Rating		Maximum letter of credit issuer limit as a percentage of Tangible Net Worth of issuer
S&P or Fitch	Moody’s	
A+	A1	0.80%
A	A2	0.75%
A-	A3	0.70%
Below A-	Below A3	Not accepted

(A) Each letter of credit issuer limit is also subject to an overall limit of $750 million per issuer.

(B) Each Bank Business Day, ERCOT will issue a report of each letter of credit issuer detailing the issuer’s dollar amount of the letters of credit currently issued to ERCOT, the issuer’s computed aggregate concentration limit, and the unused capacity under that limit. Market Participants may inquire of ERCOT about intra-day changes to the amount of posted letters of credit.

(C) If a letter of credit issuer limit is breached, Counter-Parties utilizing that issuer will be notified and no new letters of credit from the issuer will be accepted while the limit remains breached.

(D) After four months of the limit in breach, ERCOT will no longer accept new letters of credit or amendments to existing letters of credit from that issuer.

(E) Letters of credit held as collateral at the time of an issuer limit breach will not be rejected.

(F) ERCOT in its sole discretion may authorize exceptions to these limits.

(G) Revisions to the issuer limit calculation in this Section will be recommended by the Technical Advisory Committee (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.

(c) The Counter-Party may give a surety bond naming ERCOT as the beneficiary.

(i) The surety bond must be signed by a surety acceptable to ERCOT, in its sole discretion and must be in the form of ERCOT's standard surety bond form approved by the ERCOT Board. No modifications to the form are permitted.

(ii) The surety bond must be issued by an insurance company with a minimum rating of A- with S&P or Fitch or A3 with Moody's.

(iii) Surety bonds are subject to a limit of $10 million per Counter-Party per insurer and an overall limit of $100 million per insurer for all ERCOT Counter-Parties.

(d) The Counter-Party may deposit Cash Collateral with ERCOT with the understanding that ERCOT may draw part or all of the deposited cash to satisfy any overdue payments owed by the Counter-Party to ERCOT. The Cash Collateral may bear interest payable directly to the Counter-Party, but any such arrangements may not restrict ERCOT's immediate access to the cash.

(i) Interest on Cash Collateral will be calculated based on Counter-Party average Cash Collateral balances. Interest is not paid on Cash Collateral balances held by ERCOT where, in accordance with paragraph (4) of Section 16.11.7, Release of Market Participant's Financial Security Requirement, the Counter-Party's Standard Form Market Participant Agreement has been terminated and ERCOT has determined that no obligations remain owing or will become due and payable.

(ii) Once per year, ERCOT will:

(A) Return interest earned on a Counter-Party's Cash Collateral to the Counter-Party if the amount of interest earned is greater than $50; or

(B) Retain interest earned on a Counter-Party's Cash Collateral as additional Cash Collateral if the amount of interest earned is less than or equal to $50.

(iii) ERCOT has a security interest in all property delivered by the Counter-Party to ERCOT from time to time to meet the creditworthiness requirements, and that property secures all amounts owed by the Counter-Party to ERCOT.

[NPRR1112: Replace paragraph (1) above with the following upon system implementation and October 1, 2023:]

(1) A Counter-Party required to provide Financial Security under these Protocols may do so through one or more of the following means:

(a) The Counter-Party may give an unconditional, irrevocable letter of credit naming ERCOT as the beneficiary. ERCOT may, in its sole discretion, reject the letter of credit if the issuer is unacceptable to ERCOT or if the conditions under which ERCOT may draw against the letter of credit are unacceptable to ERCOT.

(i) The letter of credit must be given using the ERCOT Board-approved standard letter of credit form.

(ii) All letters of credit must be drawn on a U.S. domestic bank or a U.S. domestic office of a foreign bank.

(iii) Letters of credit must be issued by a bank or other financial institution that is acceptable to ERCOT, with a minimum rating of A- with S&P or Fitch or A3 with Moody’s.

(iv) Letters of credit are subject to an overall limit per letter of credit issuer for all ERCOT Counter-Parties as determined below:

If the issuing entity has		Then
Long-Term or Issuer Rating		Maximum letter of credit issuer limit as a percentage of Tangible Net Worth of issuer
S&P or Fitch	Moody’s	
AAA	Aaa	1.00%
AA+	Aa1	0.95%
AA	Aa2	0.90%
AA-	Aa3	0.85%
A+	A1	0.80%
A	A2	0.75%
A-	A3	0.70%
Below A-	Below A3	Not accepted

(A) Each letter of credit issuer limit is also subject to an overall limit of $750 million per issuer.

(B) Each Bank Business Day, ERCOT will issue a report of each letter of credit issuer detailing the issuer’s dollar amount of the letters of credit currently issued to ERCOT, the issuer’s computed aggregate concentration limit, and the unused capacity under that limit. Market Participants may inquire of ERCOT about intra-day changes to the amount of posted letters of credit.

(C) If a letter of credit issuer limit is breached, Counter-Parties utilizing that issuer will be notified and no new letters of credit from the issuer will be accepted while the limit remains breached.

(D) After four months of the limit in breach, ERCOT will no longer accept new letters of credit or amendments to existing letters of credit from that issuer.

(E) Letters of credit held as collateral at the time of an issuer limit breach will not be rejected.

(F) ERCOT in its sole discretion may authorize exceptions to these limits.

(G) Revisions to the issuer limit calculation in this Section will be recommended by the Technical Advisory Committee (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 Counter-Party may give a surety bond naming ERCOT as the beneficiary.

(i) The surety bond must be signed by a surety acceptable to ERCOT, in its sole discretion and must be in the form of ERCOT's standard surety bond form approved by the ERCOT Board. No modifications to the form are permitted.

(ii) The surety bond must be issued by an insurance company with a minimum rating of A- with S&P or Fitch or A3 with Moody's.

(iii) Surety bonds are subject to a limit of $10 million per Counter-Party per insurer and an overall limit of $100 million per insurer for all ERCOT Counter-Parties.

(c) The Counter-Party may deposit Cash Collateral with ERCOT with the understanding that ERCOT may draw part or all of the deposited cash to satisfy any overdue payments owed by the Counter-Party to ERCOT. The Cash Collateral may bear interest payable directly to the Counter-Party, but any such arrangements may not restrict ERCOT's immediate access to the cash.

(i) Interest on Cash Collateral will be calculated based on Counter-Party average Cash Collateral balances. Interest is not paid on Cash Collateral balances held by ERCOT where, in accordance with paragraph (4) of Section 16.11.7, Release of Market Participant's Financial Security Requirement, the Counter-Party's Standard Form Market Participant Agreement has been terminated and ERCOT has determined that no obligations remain owing or will become due and payable.

(ii) Once per year, ERCOT will:

(A) Return interest earned on a Counter-Party's Cash Collateral to the Counter-Party if the amount of interest earned is greater than $50; or

(B) Retain interest earned on a Counter-Party's Cash Collateral as additional Cash Collateral if the amount of interest earned is less than or equal to $50.

(iii) ERCOT has a security interest in all property delivered by the Counter-Party to ERCOT from time to time to meet the creditworthiness requirements, and that property secures all amounts owed by the Counter-Party to ERCOT.

16.11.4 Determination and Monitoring of Counter-Party Credit Exposure

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 that may be satisfied by any forms of Financial Security defined under paragraphs (1)(a) through (1)(d) of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements. TPEA will include all exposure not included in TPES.

(b) TPES is the positive net exposure of the Counter-Party that may be satisfied only by forms of Financial Security defined under paragraphs (1)(b) through (1)(d) of Section 16.11.3. The Future Credit Exposure (FCE) that reflects the future mark-to-market value for CRRs registered in the name of the Counter-Party is included in TPES.

[NPRR1112: Replace paragraph (1) above with the following upon system implementation and October 1, 2023:]

(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: $\text{MCE} = \text{Max}[\text{RFAF} * \text{MAF} * \text{Max}[\{\sum_e \sum_{i=1}^{96} \sum_p [\text{L}_{i, od, p} * \text{RTSPP}_{i, od, p}]/n\}, \{\sum_e \sum_{i=1}^{96} \sum_p [[[\text{L}_{i, od, p} * T2 - \text{G}_{i, od, p} * (1-NUCADJ) * T3] * \text{RTSPP}_{i, od, p}] + [\text{RTQQNET}_{i, od, p} * T5]]/n\},$ $\{\sum_e \sum_{i=1}^{96} \sum_p [\text{G}_{i, od, p} * NUCADJ * T1 * \text{RTSPP}_{i, od, p}]/\text{n}\},$ $\{\sum_e \sum_{i=1}^{96} \sum_p \text{DARTNET}_{i, od, p} * T4/n\}],$ $\text{MAF} * \text{IMCE}]$

Variable	Unit	Description
		$RTQQNET_{i, od, p} = \text{Max}[\sum_{c} (RTQQES_{i, od, p, c} - RTQQEP_{i, od, p, c}), BTCF * \sum_{c} (RTQQES_{i, od, p, c} - RTQQEP_{i, od, p, c})] * RTSPP_{i, od, p}$ $DARTNET_{i, od, p} = \text{DAM EOO Cleared}_{i, od, p} * DART_{i, od, p} + \text{DAM TPO Cleared}_{i, od, p} * DART_{i, od, p} + \text{DAM PTP Cleared}_{i, od, p} * DARTPTP_{i, od, p} - \text{DAM EOB Cleared}_{i, od, p} * DART_{i, od, p}$ Where: $G_{i, od, p}$ = *Total Metered Generation at all Resource Nodes* 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* 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 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) $RTQQNET_{i, od, p}$ = *Net QSE-to-QSE Energy Trades* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p* $RTQQES_{i, od, p, c}$ = *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* $RTQQEP_{i, od, p, c}$ = *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* $RTSPP_{i, od, p}$ = *Real-Time Settlement Point Price* for interval *i* for Operating Day *od* at Settlement Point *p* $DARTNET_{i, od, p}$ = *Net DAM activities* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p* $DART_{i, od, p}$ = *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 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*

Variable	Unit	Description
		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* 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 *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: $\text{MCE} = \text{Max}[\text{RFAF} * \text{MAF} * \text{Max}[\{\sum_e \sum_{i=1}^{96} \sum_p [\text{L}_{i, od, p} * \text{RTSPP}_{i, od, p}]/n\}, \{\sum_e \sum_{i=1}^{96} \sum_p [[[\text{L}_{i, od, p} * T2 - \text{G}_{i, od, p} * (1-NUCADJ) * T3] * \text{RTSPP}_{i, od, p}] + [\text{RTQQNET}_{i, od, p} * T5]]/n\}, \{\sum_e \sum_{i=1}^{96} \sum_p [\text{G}_{i, od, p} * NUCADJ * T1 * \text{RTSPP}_{i, od, p}]/n\}, \{\{\sum_e \sum_{i=1}^{96} \sum_p \text{DARTNET}_{i, od, p} * T4/n\} + \{\sum_e \sum_{i=1}^{96} \text{DARTASONET}_{i, od, c} * T4/n\}\}], \text{MAF} * \text{IMCE}]$ $\text{RTQQNET}_{i, od, p} = \text{Max}[\sum_c (\text{RTQQES}_{i, od, p, c} - \text{RTQQEP}_{i, od, p, c}), BTCF * \sum_c (\text{RTQQES}_{i, od, p, c} - \text{RTQQEP}_{i, od, p, c})] * \text{RTSPP}_{i, od, p}$ $\text{DARTNET}_{i, od, p} = \text{DAM EOO Cleared}_{i, od, p} * \text{DART}_{i, od, p} + \text{DAM TPO Cleared}_{i, od, p} * \text{DART}_{i, od, p} + \text{DAM PTP Cleared}_{i, od, p} * \text{DARTPTP}_{i, od, p} - \text{DAM EOB Cleared}_{i, od, p} * \text{DART}_{i, od, p}$ $\text{DARTASONET}_{i, od} = \text{DAM ASOO Cleared}_{i, od} * \text{DARTMCPC}_{i, od}$

Where:

$G_{i,\ od,\ p}$ = *Total Metered Generation at all Resource Nodes* 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* 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 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)

$RTQQNET_{i,\ od,\ p}$ = *Net QSE-to-QSE Energy Trades* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*

$RTQQES_{i,\ od,\ p,\ c}$ = *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*

$RTQQEP_{i,\ od,\ p,\ c}$ = *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*

$DARTASONET_{i,\ od}$ = *Net DAM Ancillary Service Only activities* for interval *i* for Operating Day *od*

DAM ASOO Cleared $_{i,\ od}$ = DAM Ancillary Service Only Offers Cleared in DAM for interval *i* for Operating Day *od*

$DARTMCPC_{i,\ od}$ = Day-Ahead – Real-Time MCPC Spread for interval *i* for Operating Day *od*

BTCF = *Bilateral Trades Credit Factor*

$RTSPP_{i,\ od,\ p}$ = *Real-Time Settlement Point Price* for interval *i* for Operating Day *od* at Settlement Point *p*

$DARTNET_{i,\ od,\ p}$ = *Net DAM activities* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*

$DART_{i,\ od,\ p}$ = *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 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*

Variable	Unit	Description
		DAM PTP Cleared $_{i, od, p}$ = *DAM Point-to-Point (PTP) Obligations Cleared* for interval *i* for Operating Day *od* at Settlement Point *p* 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 *od* = Operating Day *p* = A Settlement Point
IMCE	$	*Initial Minimum Current Exposure* $\text{IMCE} = \text{TOA} * (\text{SWCAP} * nm * cif\%)$
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

Parameter	Unit	Current Value*
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.

16.11.4.2 Determination of Counter-Party Initial Estimated Liability

(1) For each Counter-Party, except those Counter-Parties that are only CRR Account Holders, ERCOT shall determine an Initial Estimated Liability (IEL) for purposes of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

(2) For a Counter-Party that has all its QSEs representing only LSEs, ERCOT shall calculate the IEL using the following formula:

$$\mathbf{IEL = DEL * Max\ [0.2, RTEFL] * RTAEP * (M1 + M2)}$$

The above variables are defined as follows:

Variable	Unit	Description
IEL	$	*Initial Estimated Liability*—The Counter-Party's Initial Estimated Liability.
DEL	MWh	*Daily Estimated Load*—The Counter-Party's estimated average daily Load as determined by ERCOT based on information provided by the Counter-Party.
RTEFL	none	*Real-Time Energy Factor for Load*—The ratio of the Counter-Party's estimated energy purchases in the RTM as determined by ERCOT based on

		information provided by the Counter-Party, to the Counter-Party's Daily Estimated Load.
RTAEP	\$/MWh	*Real-Time Average Energy Price*—Average Settlement Point Price for the "ERCOT 345" as defined in Section 3.5.2.5, ERCOT Hub Average 345 kV Hub (ERCOT 345), based upon the previous seven days' average Real-Time Settlement Point Prices.

(3) For a Counter-Party that has all its QSEs representing only Resources, ERCOT shall calculate the IEL using the following formula:

$$\mathbf{IEL} = \mathbf{DEG * Max\ [0.2, RTEFG] * RTAEP * (M1 + M2)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
IEL	\$	*Initial Estimated Liability*—The Counter-Party's Initial Estimated Liability.
DEG	MWh	*Daily Estimated Generation*—The Counter-Party's estimated average daily generation as determined by ERCOT based on information provided by the Counter-Party.
RTEFG	none	*Real-Time Energy Factor for Generation*—The ratio of the Counter-Party's QSE to QSE estimated energy sales as determined by ERCOT based on information provided by the Counter-Party, to the Counter-Party's Daily Estimated Generation.
RTAEP	\$/MWh	*Real-Time Average Energy Price*—Average Settlement Point Price for the "ERCOT 345" as defined in Section 3.5.2.5 based upon the previous seven days average Real-Time Settlement Point Prices.

(4) For a Counter-Party that has QSEs representing both LSE and Resources, ERCOT shall calculate the Counter-Party's IEL using the following formula:

$$\mathbf{IEL} = \mathbf{DEL * Max\ [0.1, RTEFL] * RTAEP * (M1 + M2) + DEG * Max\ [0.1, RTEFG] * RTAEP * (M1 + M2)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
IEL	$	*Initial Estimated Liability*—The Counter-Party's Initial Estimated Liability.
DEL	MWh	*Daily Estimated Load*—The Counter-Party's estimated average daily Load as determined by ERCOT based on information provided by the Counter-Party.
DEG	MWh	*Daily Estimated Generation*—The Counter-Party's estimated average daily generation as determined by ERCOT based on information provided by the Counter-Party.
RTEFL	none	*Real-Time Energy Factor for Load*—The ratio of the Counter-Party's estimated energy purchases in the RTM as determined by ERCOT based on information provided by the Counter-Party, to the Counter-Party's Daily Estimated Load.
RTAEP	$/MWh	*Real-Time Average Energy Price*—Average Settlement Point Price for the "ERCOT 345" as defined in Section 3.5.2.5 based upon the previous seven days' average Real-Time Settlement Point Prices.
RTEFG	none	*Real-Time Energy Factor for Generation*—The ratio of the Counter-Party's QSE to QSE estimated energy sales as determined by ERCOT, based on information provided by the Counter-Party, to the Counter-Party's Daily Estimated Generation.

(5) For a Counter-Party that has all its QSEs representing neither Load nor generation, and that is not representing a CRR Account Holder, the IEL is equal to IMCE as defined in paragraph (2) of Section 16.11.4.1, Determination of Total Potential Exposure for a Counter-Party.

(6) For a Counter-Party that is only a CRR Account Holder and is not a QSE, the IEL is zero.

16.11.4.3 Determination of Counter-Party Estimated Aggregate Liability

(1) After a Counter-Party commences activity in ERCOT markets, ERCOT shall monitor and calculate the Counter-Party's EAL based on the formulas below.

EAL $_q$ = **Max [IEL during the first 40-day period only beginning on the date that the Counter-Party commences activity in ERCOT markets, RFAF * Max {RTLE during the previous *lrq* days}, RTLF] + DFAF * DALE + Max [RTLCNS, Max {URTA during the previous *lrq* days}] + OUT $_q$ + ILE $_q$**

EAL $_t$ = **Max [RFAF * Max {RTLE during the previous *lrt* days}, RTLF] + DFAF * DALE + Max [RTLCNS, Max {URTA during the previous *lrt* days}] + OUT $_t$**

EAL $_a$ = **OUT $_a$**

ERCOT may adjust the number of days used in determining the highest RTLE and/or URTA, and/or to exclude specific Operating Days to calculate RTLE, URTA, OUT, or DALE.

The above variables are defined as follows:

Variable	Unit	Description
EAL_q	$	*Estimated Aggregate Liability for all the QSEs* represented by a Counter-Party if at least one QSE represented by the Counter-Party represents either Load or generation.
EAL_t	$	*Estimated Aggregate Liability for all the QSEs* represented by a Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation.
EAL_a	$	*Estimated Aggregate Liability for all the CRR Account Holders* represented by the Counter-Party.
IEL	$	*Initial Estimated Liability for all the QSEs* represented by the Counter-Party if at least one QSE represented by the Counter-Party represents either Load or generation as defined in paragraphs (1), (2), (3) and (4) of Section 16.11.4.2, Determination of Counter-Party Initial Estimated Liability.
q		QSEs represented by Counter-Party.
t		QSEs represented by a Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation.
a		CRR Account Holders represented by Counter-Party.
RTLE	$	*Real-Time Liability Extrapolated*—M1 multiplied by the sum of the net amount, with zero substituted for missing values, due to or from ERCOT by the Counter-Party in the 14 most recent Operating Days for which RTM Initial Statements are produced for Counter-Parties according to the ERCOT Settlement Calendar divided by 14.
URTA	$	*Unbilled Real-Time Amount*—M2 multiplied by the sum of the net amount, with zero substituted for missing values, due to or from ERCOT by the Counter-Party in the 14 most recent Operating Days for which RTM Initial Statements are produced for Counter-Parties according to the ERCOT Settlement Calendar divided by 14.
RTL	$	*Real-Time Liability*—The estimated or settled amounts due to or from ERCOT due to activities in the RTM for an Operating Day, as defined in Section 16.11.4.3.2, Real-Time Liability Estimate.
RTLCNS	$	*Real-Time Liability Completed and Not Settled*—For each Operating Day that is completed but not settled, ERCOT shall calculate RTL adjusted up by *rtlcu%* if there is a net amount due to ERCOT or adjusted down by *rtlcd%* if there is a net amount due to the QSE. RTLCNS = Sum of Max RTL(*rtlcu%* * RTL, *rtlcd%* * RTL) for all completed and not settled Operating Days Where: *rtlcu* = Real-Time Liability Markup *rtlcd* = Real-Time Liability Markdown
RTLF	$	*Real-Time Liability Forward*—rtlfp% of the sum of estimated RTL from the most recent seven Operating Days. RTLF = *rtlf%* of the Sum of Max RTL(*rtlcu%* * RTL, *rtlcd%* * RTL) for the most recent seven Operating Days Where: *rtlfp* = Real-Time Liability Forward

Variable	Unit	Description
OUT_q	$	*Outstanding Unpaid Transactions*—Outstanding unpaid transactions for all QSEs represented by the Counter-Party, which include (a) outstanding Invoices to the Counter-Party; (b) estimated unbilled items to the Counter-Party, to the extent not adequately accommodated in the RTLE calculation (including resettlements and other known liabilities); and (c) estimated CRR Auction revenue available for distribution for Operating Days in the previous two months, to the extent not invoiced to the Counter-Party. Invoices will not be considered outstanding for purposes of this calculation the Business Day after that Invoice payment is received. $\text{OUT}_q = \text{OIA}_q + \text{UDAA}_q + \text{UFA}_q + \text{UTA}_q + \text{CARD}$ Where: OIA_q = *Outstanding Invoice Amounts for all the QSEs represented by the Counter-Party* – Sum of any outstanding Real-Time and Day-Ahead unpaid invoices issued to the Counter-Party, including but not limited to CRR Auction Revenue Distribution (CARD) Invoices, CRR Balancing Account Invoices, Default Uplift Invoices, Securitization Uplift Charge Reallocation Invoices, and other miscellaneous Invoices. Also included are the amounts or portions of Invoices due to the Counter-Party that have been short-paid as a result of a default or non-payment of Invoices due to ERCOT by another Counter-Party. UDAA_q = *Unbilled Day-Ahead Amounts for all the QSEs represented by the Counter-Party* – Sum of DAL for all the QSEs represented by the Counter-Party for all Operating Days for which a DAM Statement is not generated. UFA_q = *Unbilled Final Amounts for all the QSEs represented by the Counter-Party* – Unbilled final extrapolated days (*ufd)* multiplied by the sum of the net amount due to or from ERCOT for all QSEs represented by the Counter-Party for Operating Days for which RTM Final Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM Final Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days. UTA_q = *Unbilled True-Up Amounts for all the QSEs represented by the Counter-Party* – Unbilled true-up extrapolated days (*utd)* multiplied by the sum of the net amount due to or from ERCOT by the Counter-Party for all the QSEs represented by the Counter-Party for Operating Days for which RTM True-Up Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM True-Up Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days.

Variable	**Unit**	**Description**
		CARD = *CRR Auction Revenue Distribution for all the QSEs represented by the Counter-Party* – Estimate of the Counter-Party's unpaid allocation of CRR Auction revenues that have already been collected but have not been paid out to all QSEs represented by the Counter-Party. CRR Auction revenues that have been earned but not billed are distributed based on the following Load Ratio Shares (LRSs): (a) Zonal LRS applied to revenues from CRRs cleared and have source and sink points located within a 2003 ERCOT Congestion Management Zone (CMZ), and (b) ERCOT-wide LRS applied to all other CRR Auction revenues. The LRS will be based on the latest completed operating month for which LRS are available.
DAL	$	*Day-Ahead Liability*—The estimated or settled amounts due to or from ERCOT due to activities in the DAM for an Operating Day, as defined in Section 16.11.4.3.1, Day-Ahead Liability Estimate.
OUT $_t$	$	*Outstanding Unpaid Transactions*—Outstanding unpaid transactions for all QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation, which include (a) outstanding Invoices to the Counter-Party; (b) estimated unbilled items to the Counter-Party, to the extent not adequately accommodated in the RTLE calculation (including resettlements and other known liabilities). $\text{OUT}_t = \text{OIA}_t + \text{UDAA}_t + \text{UFA}_t + \text{UTA}_t$ Where: OIA $_t$ = *Outstanding Invoice Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation* – Sum of any outstanding Real-Time and Day-Ahead unpaid Invoices issued to the Counter-Party, including but not limited to CRR Balancing Account Invoices, Default Uplift Invoices and other miscellaneous Invoices. Also included are the amounts or portions of invoices due to the Counter-Party that have been short-paid as a result of a Default or non-payment of invoices due to ERCOT by another Counter-Party. UDAA $_t$ = *Unbilled Day-Ahead Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation* – Sum of DAL for all the QSEs represented by the Counter-Party for all Operating Days for which DAM Statement is not generated. UFA $_t$ = *Unbilled Final Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation – ufd* multiplied by the sum of the net amount due to or from ERCOT for all QSEs represented by the Counter-

Variable	Unit	Description
		Party for Operating Days for which RTM Final Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM Final Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days. UTA_t = *Unbilled True-Up Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation – utd* multiplied by the sum of the net amount due to or from ERCOT by the Counter-Party for all the QSEs represented by the Counter-Party for Operating Days for which RTM True-Up Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM True-Up Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days.
OUT_a	$	*Outstanding Unpaid Transactions for all CRR Account Holders represented by the Counter-Party*—Outstanding, unpaid transactions of all the CRR Account Holders represented by the Counter-Party, which include outstanding Invoices to the Counter-Party. Invoices will not be considered outstanding for purposes of this calculation the Business Day after that Invoice payment is received. $\text{OUT}_a = \text{OIA}_a + \text{UDAA}_a$ Where: OIA_a = *Outstanding Invoice Amounts for all the CRR Account Holders represented by the Counter-Party* – Sum of any outstanding Real-Time and Day-Ahead unpaid Invoices issued to the Counter-Party including but not limited to CRR Balancing Account Invoices, Default Uplift Invoices and other miscellaneous Invoices. Also included are the amounts or portions of Invoices due to the Counter-Party that have been short-paid as a result of a default or non-payment of Invoices due to ERCOT by another Counter-Party. UDAA_a = *Unbilled Day-Ahead Amounts for all the CRR Account Holders represented by the Counter-Party* – Sum of DAL of all the CRR Account Holders represented by the Counter-Party for all Operating Days for which DAM Statement is not generated.
ILE_q	$	*Incremental Load Exposure*—In the event of a Mass Transition necessitated by the default of a Counter-Party representing a QSE associated with an LSE, ERCOT may adjust the TPE of the Counter-Parties representing QSEs that are qualified as Providers of Last Resort (POLRs) to reflect the estimated Incremental Load Exposure (ILE) resulting from the Mass Transition. The adjustment will be based on the POLR's *pro rata* share of the defaulting Counter-Party's RTLE, based on the total estimated Electric Service Identifiers (ESI IDs) to be transitioned. ERCOT will communicate any such adjustment to the Authorized Representative of each Counter-Party who is a POLR within 24

Variable	**Unit**	**Description**
		hours of the initiation of a Mass Transition. The ILE adjustment will remain in place no more than the number of days necessary to effect a Mass Transition for the defaulting Counter-Party, after which time the incremental exposure will be fully reflected in the Counter-Party's unadjusted TPE.
DALE	$	*Average Daily Day-Ahead Liability Extrapolated*—M1 multiplied by the sum of the net amount, with zero substituted for missing values, due to or from ERCOT by the Counter-Party in the seven most recent Operating Days for which DAM Settlement Statements are produced for Counter-Parties according to the ERCOT Settlement Calendar divided by seven.
M1		M1 = M1a + M1b—Multiplier for DALE and RTLE. Provides for forward risk during a Counter-Party termination upon default based upon the sum of the time period required for any termination upon default (M1a) and the time period required for a Mass Transition only (M1b). The M1a component is applicable to all Counter-Parties. The M1b component is applicable only to Counter-Parties representing any QSE associated with a LSE. M1a = Time period required for any termination from an Operating Day. M1a is comprised of a fixed value (*M1d*), representing days from issuance of a collateral call to termination, and a calendar day-specific variable value. For any Operating Day, M1a is equal to the total number of forward calendar days encompassed by starting on the Operating Day, including *M1d* Bank Business Days forward, and adding any ERCOT holidays that are also Bank Business Days. M1b = Weighted average transition days = Min(B, (2 + Max(1, (u+1)/2))*(1-DF)), rounded up to whole days. Where: u = (ESIn/r) Unscaled number of days to transition. B = Benchmark value. Used to establish a maximum M1 value. ESIn = Number of ESI IDs associated with an individual Counter-Party. This value will be updated no less often than annually by ERCOT and updated values communicated to individual Counter-Parties. Counter-Parties entering the market will provide an estimated number of ESI IDs for use during their first six months of market activity. Subsequent to this time, the value for that Counter-Party shall be updated by ERCOT concurrently with other Counter-Parties with QSEs representing an LSE. r = Assumed ESI ID daily transition rate. DF = Discount Factor applied to M1b if the Counter-Party is eligible for unsecured credit under Section 16.11.2, Requirements for Setting a Counter-Party's Unsecured Credit Limit, or meets other creditworthiness standards that may be developed and approved by TAC and the ERCOT Board.

Variable	Unit	Description
		[NPRR1112: Replace the description above with the following upon system implementation and October 1, 2023:] M1 = M1a + M1b—Multiplier for DALE and RTLE. Provides for forward risk during a Counter-Party termination upon default based upon the sum of the time period required for any termination upon default (M1a) and the time period required for a Mass Transition only (M1b). The M1a component is applicable to all Counter-Parties. The M1b component is applicable only to Counter-Parties representing any QSE associated with a LSE. M1a = Time period required for any termination from an Operating Day. M1a is comprised of a fixed value (*M1d*), representing days from issuance of a collateral call to termination, and a calendar day-specific variable value. For any Operating Day, M1a is equal to the total number of forward calendar days encompassed by starting on the Operating Day, including *M1d* Bank Business Days forward, and adding any ERCOT holidays that are also Bank Business Days. M1b = Weighted average transition days = Min(B, (2 + Max(1, (u+1)/2))*(1-DF)), rounded up to whole days Where: u = (ESIn/r) Unscaled number of days to transition. B = Benchmark value. Used to establish a maximum M1 value. ESIn = Number of ESI IDs associated with an individual Counter-Party. This value will be updated no less often than annually by ERCOT and updated values communicated to individual Counter-Parties. Counter-Parties entering the market will provide an estimated number of ESI IDs for use during their first six months of market activity. Subsequent to this time, the value for that Counter-Party shall be updated by ERCOT concurrently with other Counter-Parties with QSEs representing an LSE. r = Assumed ESI ID daily transition rate. DF = Discount Factor applied to M1b if the Counter-Party meets other creditworthiness standards that may be developed and approved by TAC and the ERCOT Board.
M2		Multiplier for URTA.
RFAF	None	*Real-Time Forward Adjustment Factor*—The adjustment factor for RTM-related forward exposure as defined in Section 16.11.4.3.3, Forward Adjustment Factors.
DFAF	None	*Day-Ahead Forward Adjustment Factor*—The adjustment factor for DAM-related forward exposure as defined in Section 16.11.4.3.3.

Variable	**Unit**	**Description**
lrq	Days	Look-back period for RTM to find the maximum of RTLE or URTA for all QSEs represented by the Counter-Party if any of the QSEs represented by the Counter-Party represent either Load or generation.
lrt	Days	Look-back period for RTM to find the maximum of RTLE or URTA for all QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation.

The above parameters are defined as follows:

Parameter	**Unit**	**Current Value***
rtlcu	Percentage	110%
rtlcd	Percentage	90%
rtlfp	Percentage	150%
ufd	Days	55
utd	Days	180
M1d	Days	8
B	Days	8
r	none	100,000 per day
DF	Percentage	0
M2	Days	9
lrq	Days	40
lrt	Days	20
* 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.		

16.11.4.3.1 Day-Ahead Liability Estimate

(1) ERCOT shall estimate Day-Ahead Liability (DAL) for an Operating Day as the sum of estimates for the following DAM Settlement charges and payments:

(a) Section 4.6.2.1, Day-Ahead Energy Payment;

(b) Section 4.6.2.2, Day-Ahead Energy Charge;

(c) Section 4.6.3, Settlement for PTP Obligations Bought in DAM;

(d) Section 4.6.4.1.1, Regulation Up Service Payment;

(e) Section 4.6.4.1.2, Regulation Down Service Payment;

(f) Section 4.6.4.1.3, Responsive Reserve Service Payment;

(g) Section 4.6.4.1.4, Non-Spinning Reserve Service Payment;

[NPRR992: Insert item (h) below upon system implementation of NPRR863 and renumber accordingly:]

(h) Section 4.6.4.1.5, ERCOT Contingency Reserve Service Payment;

(h) Section 4.6.4.2.1, Regulation Up Service Charge;

(i) Section 4.6.4.2.2, Regulation Down Service Charge;

(j) Section 4.6.4.2.3, Responsive Reserve Service Charge;

(k) Section 4.6.4.2.4, Non-Spinning Reserve Service Charge;

[NPRR992: Insert item (m) below upon system implementation of NPRR863 and renumber accordingly:]

(m) Section 4.6.4.2.5, ERCOT Contingency Reserve Service Charge;

(l) Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM;

(m) Section 7.9.1.2, Payments for PTP Options Settled in DAM;

(n) Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM; and

(o) Section 7.9.1.6, Payments for PTP Options with Refund Settled in DAM.

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 Metered Generation (RTMG) 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 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;

[NPRR1054: Delete item (e) above upon system implementation and renumber accordingly.]

(f) Section 6.6.3.9, 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 (f) above with the following upon system implementation:]

(f) Section 6.6.3.9, 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;

(g) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules; and

[NPRR1013: Insert items (h)-(l) below upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

(h) Section 6.7.5.1, Regulation Up Payments and Charges;

(i) Section 6.7.5.2, Regulation Down Payments and Charges;

(j) Section 6.7.5.3, Responsive Reserve Payments and Charges;

(k) Section 6.7.5.4, Non-Spinning Reserve Payments and Charges; and

(l) Section 6.7.5.5, ERCOT Contingency Reserve Service Payments and Charges.

(h) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time.

16.11.4.3.3 Forward Adjustment Factors

(1) Forward adjustment factors are used to adjust TPEA based on electricity futures prices.

(a) Futures Weekly Average Price (FWAP):

$$\text{FWAP}_{w} = (1/nfwh) * \sum_{fwh=1}^{nfwh}[\text{FHP}_{fwh,\ rhub}]$$

(b) Projected Real-Time Forward Average Price (PRFAP):

$$\text{PRFAP} = \sum_{w=1}^{3}[RWF_{w} * \text{FWAP}_{w}]$$

(c) Projected Day-Ahead Forward Average Price (PDFAP):

$$\text{PDFAP} = \sum_{w=1}^{3}[DWF_{w} * \text{FWAP}_{w}]$$

(d) Historic Real-Time Settled Average Price (HRSAP):

$$\text{HRSAP} = (1/nhrh) * \sum_{hrh=1}^{nhrh}\sum_{i=1}^{4}[\text{RTSPP}_{hrh,\ i,\ rhub}]/4$$

(e) Historic Day-Ahead Settled Average Price (HDSAP):

$$\text{HDSAP} = (1/nhdh) * \sum_{hdh=1}^{nhdh}[\text{DASPP}_{hdh,\ rhub}]$$

(f) Real-Time Forward Adjustment Factor (RFAF):

$$\text{RFAF} = \text{PRFAP}/\text{HRSAP}$$

(g) Day-Ahead Forward Adjustment Factor (DFAF):

$$\text{DFAF} = \text{PDFAP}/\text{HDSAP}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
PRFAP	$/MWh	*Projected Real-Time Forward Average Price*—The average RTM price per MWh projected forward based on futures market prices.
PDFAP	$/MWh	*Projected Day-Ahead Forward Average Price*—The average DAM price per MWh projected forward based on futures market prices.

w	None	One of the three consecutive forward weeks beginning with the current Operating Day.
RWF_w	None	*Real-Time Weight Factor for forward week w* such that $\sum_{w=1}^{3} RWF_w = 1$
DWF_w	None	*Day-Ahead Weight Factor for forward week w* such that $\sum_{w=1}^{3} DWF_w = 1$
fwh	None	*Forward Week Hour*—An Operating Hour from a forward week *w*.
nfwh	None	*Number of Forward Week Hours*—Total number of hours in a forward week.
rhub	None	*Reference Hub*—The electrical Hub used as a reference for futures mark-to-market prices.
FWAP_w	$/MWh	*Futures Weekly Average Price for week w*—The average futures price for the hours of the forward week *w*.
$\text{FHP}_{fwh,\ rhub}$	$/MWh	*Futures Hourly Price of the Reference Hub rhub for Forward Week Hour fwh*—The most recent mark-to-market price available for an electricity futures product that is applicable to the forward week hour *fwh* for the reference Hub *rhub*. ERCOT will disclose to the market the source of its selected electricity futures product(s) used for FHP. In the event that an ERCOT-selected electricity futures product(s) becomes unavailable or unsuitable for the intended purpose, ERCOT will select a substitute electricity futures product(s). ERCOT shall set the value of RFAF to 1 and DFAF to 1, and provide Notice of this change as soon as practicable, until such time as a substitute electricity futures product(s) is selected and implemented by ERCOT. ERCOT will notify Market Participants of any change in the electricity futures product(s) at least 60 days prior to the beginning of their use. In the event that 60 days' Notice cannot be given, ERCOT will notify Market Participants as soon as practicable prior to use.
hrh	None	*Historic Real-Time Hour*—An Operating Hour that is settled and used in the most recent RTLE calculation.
nhrh	None	*Number of Historic Real-Time Hours*—Total number of historic Real-Time hours that are settled and used in the most recent RTLE calculation.
i	None	*Settlement Interval*—A 15-minute interval that is part of an Operating Hour.
$\text{RTSPP}_{hrh,\ i,\ rhub}$	$/MWh	Real-Time Settlement Point Price for i^{th} interval that is part of Operating Hour *hrh* for the Settlement Point *rhub*.
HRSAP	$/MWh	*Historic Real-Time Settled Average Price*—The average historic Real-Time settled price.
HDSAP	$/MWh	*Historic Day-Ahead Settled Average Price*—The average historic Day-Ahead settled price.
hdh	None	*Historic Day-Ahead Hour*—An Operating Hour that is settled and used in the most recent DALE calculation.
nhdh	None	*Number of Historic Day-Ahead Hours*—Total number of historic day-ahead hours that are settled and used in the most recent DALE calculation.
$\text{DASPP}_{hrh,\ rhub}$	$/MWh	Day-Ahead Settlement Point Price for Operating Hour *hdh* for the Settlement Point *rhub*.
RFAF	None	*Real-Time Forward Adjustment Factor.*
DFAF	None	*Day-Ahead Forward Adjustment Factor.*

The above parameters are defined as follows:

Parameter	Unit	Current Value*
$rhub$	None	ERCOT North Hub
RWF_1	None	1/3
RWF_2	None	1/3
RWF_3	None	1/3
DWF_1	None	1/3
DWF_2	None	1/3
DWF_3	None	1/3
* The current value for the parameters referenced in the 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.		

16.11.4.4 *[RESERVED]*

16.11.4.5 Determination of the Counter-Party Future Credit Exposure

(1) ERCOT shall monitor and calculate the Counter-Party's FCE for all the CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT.

$$\mathbf{FCE}_{a} = \mathbf{FCEOBL}_{a} + \mathbf{FCEOPT}_{a}$$

The above variables are defined as follows:

Variable	Unit	Description
FCE_a	\$	*Future Credit Exposure* for all CRRs held by *all CRR Account Holders* represented by the Counter-Party.
FCEOBL_a	\$	*Future Credit Exposure for PTP Obligations* for all PTP Obligations held by all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT, for all Operating Days in the current operating month, Prompt Month, and all Forward Months.
FCEOPT_a	\$	*Future Credit Exposure for PTP Options* for all PTP Options held by all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT, for all Operating Days remaining in the current operating month and Prompt Month.
a	none	All CRR Account Holders represented by the Counter-Party.

(2) The Counter-Party's FCE for PTP Obligations (FCEOBL) held by all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT are calculated as follows:

$$\mathbf{FCEOBL}_{a} = \sum_{m} [(\sum_{h} \sum_{j,k} \mathbf{NAOBLMW}_{m,h,(j,k)}) * (-\mathbf{Min}(0, \mathbf{PWA}_{ci100,m}, \mathbf{PWACP}_{m}))]$$

$$\mathbf{PWACP}_{m} = \sum_{h} \sum_{j,k} [\mathbf{NAOBLMW}_{m,h,(j,k)} * \mathbf{EACP}_{m,h,(j,k)}] / \sum_{h} \sum_{j,k} [\mathbf{NAOBLMW}_{m,h,(j,k)}]$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$FCEOBL_{a}$	$	*Future Credit Exposure for PTP Obligations* for all PTP Obligations held by all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT for all Operating Days in the current operating month, Prompt Month, and all Forward Months.
$NAOBLMW_{m, h, (j, k)}$	MW	*Net Awarded PTP Obligations*—Net awarded PTP Obligations with the source *j* and sink *k* for the hour *h* and month *m* owned by all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT for all Operating Days in the current operating month, Prompt Month, and Forward Months.
$PWA_{ci100, m}$	$/MW per hour	*Portfolio Weighted Adder*—The portfolio weighted adder calculated as the 100th percentile of a volume weighted average rolling consecutive DAM settled price for all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT based on volumes owned for the month *m*, over a period that represents a month for each product type (18 days for 5*16, 8 days for 2*16, 28 days for 7*8). The look-back period for DAM settled prices shall be the lesser of January 1, 2011 to the current time, and the current time minus three years. If historical Day-Ahead Settlement Point Prices (DASPPs) are not available for a Settlement Point for one or more Operating Days, ERCOT will designate a proxy Settlement Point for this purpose, and the DASPPs of the proxy Settlement Point of corresponding Operating Days are used.
$PWACP_{m}$	$/MW per hour	*Portfolio Weighted Auction Clearing Price*—The portfolio weighted auction clearing price calculated as the volume weighted auction clearing price for all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT based on the most recent auction clearing price for the month *m* and volumes owned for the month *m.*
$EACP_{m, h, (j, k)}$	$/MW per hour	*Effective Auction Clearing Price*— The auction clearing price with the source *j* and sink *k* for the hour *h,* and month *m*. For each CRR PTP Obligation, this value is equal to the auction clearing price of an awarded CRR selected as follows: (a) Awarded CRRs with the source *j* and sink *k* containing hour *h* and operating month *m* are selected from the set of unexpired awarded PTP Obligations. If no awarded CRRs are found the EACP value is zero. (b) If (a) results in more than one awarded CRR, awarded CRRs with the most recent award date are selected. (c) If (b) results in more than one awarded CRR, then the awarded CRR with the lowest auction clearing price is selected.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
m	none	An operating month.
h	none	An Operating Hour.
a	none	All CRR Account Holders represented by the Counter-Party.
ci100	none	100th percentile confidence interval.

(3) The FCE for PTP Options (FCEOPT) held by all the CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT are calculated as follows:

$$\mathbf{FCEOPT}_{a} = -\sum_{m}\sum_{h}\sum_{j,k}\left[(\mathbf{NAOPTMW}_{m,h,(j,k)}) * \mathbf{Max}(0, \mathbf{A}_{ci99,\,ctou,\,(j,k)})\right]$$

The above variables are defined as follows:

Variable	Unit	Description
FCEOPT_{a}	$	*Future Credit Exposure for PTP Options*—FCE for all PTP Options held by all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT for all Operating Days remaining in the current operating month and Prompt Month.
$\text{A}_{ci99,\,ctou,\,(j,k)}$	$/MW per hour	*Path Specific DAM Based Adder*—Path specific DAM based adder calculated as 99th percentile of the average rolling consecutive DAM settled price for the CRR source *j* and sink *k* over a period that represents a month for each CRR Time Of Use (TOU) *ctou* product type (18 days for 5*16, 8 days for 2*16, 28 days for 7*8). The look-back period for DAM settled prices shall be the lesser of January 1, 2011 to the current time, and the current time minus three years. If historical DASPPs are not available for a Settlement Point for one or more Operating Days, ERCOT will designate a proxy Settlement Point for this purpose, and the DASPPs of the proxy Settlement Point of corresponding Operating Days are used.
$\text{NAOPTMW}_{m,h,(j,k)}$	MW	*Net Awarded PTP Options*—Net awarded PTP Options with the source *j* and sink *k* for the hour *h* and month *m* owned by all CRR Account Holders represented by the Counter-Party as CRR Owner of record at ERCOT for remaining Operating Days in the current operating month, and Prompt Month.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
m	none	An operating month.
ctou	none	CRR Time Of Use block.
h	none	An Operating Hour.
a	none	All CRR Account Holders represented by the Counter-Party.
ci99	none	99^{th} percentile confidence interval.

16.11.4.6 Determination of Counter-Party Available Credit Limits

(1) ERCOT shall calculate an Available Credit Limit for the CRR Auction (ACLC) and an Available Credit Limit for the DAM (ACLD) as follows:

(a) ACLC for each Counter-Party equal to the maximum of zero and the net of its:

(i) Secured Financial Security; minus

(ii) (1+ACLIRF) * TPES; minus

(iii) Net Positive Exposure of approved CRR Bilateral Trades; minus

(iv) Maximum of:

(A) Zero; and

(B) ((1+ACLIRF) * TPEA) minus the Unsecured Credit Limit minus Financial Security defined as guarantees in paragraph (1)(a) of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

(b) ACLD for each Counter-Party equal to the maximum of zero and the net of its:

(i) Unsecured Credit Limit; plus

(ii) Financial Security defined as guarantees in paragraph (1)(a) of Section 16.11.3; plus

(iii) Remainder Collateral; minus

(iv) ACLIRF * TPES; minus

(v) (1+ACLIRF) * TPEA.

(c) If all or part of a Counter-Party's ACLC and/or ACLD cannot be computed due to an ERCOT computer system failure or Market Suspension, then ERCOT shall estimate ACLC and/or ACLD for that Counter-Party and provide the information used to determine such estimates to that Counter-Party. If all or part of ACLC and/or ACLD cannot be estimated with current data, then the most recently available values shall be used to determine the Counter-Party's ACLC and/or ACLD. ERCOT shall provide electronic Notice, as soon as practicable, to Counter-Parties when utilizing this methodology, and shall further provide electronic Notice to Counter-Parties when current data is restored and available to calculate ACLC and ACLD under paragraphs (a) and (b) above.

The above parameters are defined as follows:

Parameter	**Unit**	**Current Value***
ACLIRF	Percentage	10% — *ACL Incremental Risk Factor.*
* 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.		

[NPRR1112: Replace paragraph (1) above with the following upon system implementation and October 1, 2023:]

(1) ERCOT shall calculate an Available Credit Limit for the CRR Auction (ACLC) and an Available Credit Limit for the DAM (ACLD) as follows:

(a) ACLC for each Counter-Party equal to the maximum of zero and the net of its:

(i) Secured Financial Security; minus

(ii) (1+ACLIRF) * TPES; minus

(iii) Net Positive Exposure of approved CRR Bilateral Trades; minus

(iv) Maximum of:

(A) Zero; and

(B) ((1+ACLIRF) * TPEA).

(b) ACLD for each Counter-Party equal to the maximum of zero and its:

(i) Remainder Collateral; minus

(ii) ACLIRF * TPES; minus

(iii) (1+ACLIRF) * TPEA.

(c) If all or part of a Counter-Party's ACLC and/or ACLD cannot be computed due to an ERCOT computer system failure or Market Suspension, then ERCOT shall estimate ACLC and/or ACLD for that Counter-Party and provide the information used to determine such estimates to that Counter-Party. If all or part of ACLC and/or ACLD cannot be estimated with current data, then the most recently available values shall be used to determine the Counter-Party's ACLC and/or ACLD. ERCOT shall provide electronic Notice, as soon as practicable, to Counter-Parties when utilizing this methodology, and shall further provide electronic Notice to Counter-Parties when current data is restored and available to calculate ACLC and ACLD under paragraphs (a) and (b) above.

The above parameters are defined as follows:

Parameter	**Unit**	**Current Value***
ACLIRF	Percentage	10% — *ACL Incremental Risk Factor.*
* 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.		

16.11.4.6.1 Credit Requirements for CRR Auction Participation

(1) As a requirement for participation in any CRR Auction, each Counter-Party participating in any CRR Auction, including those as permitted by Sections 16.11.6.1.4, Repossession of CRRs by ERCOT, and 16.11.6.1.5, Declaration of Forfeit of CRRs, shall communicate

to ERCOT the credit limit it would like to establish for the CRR Auction prior to the close of the CRR bid submission window.

(2) Consistent with paragraph (4)(c)(ii) of Section 7.5.1, Nature and Timing, ERCOT shall only modify the credit limit date in paragraph (1) above under a condition in which an ERCOT computer system failure causes Counter-Parties to be delayed or unable in submitting their credit limits for the CRR Auction and ERCOT determines that the successful execution of the CRR Auction would be jeopardized without such modification. In such an event, ERCOT will issue a Market Notice advising of the revised credit limit date and its cause.

(3) ERCOT shall assign the ACL locked for CRR Auction for each Counter-Party participating in any CRR Auction as the lower of the Counter-Party's:

(a) Requested credit limit, as described in paragraph (1) above;

(b) ACLC, calculated in accordance with paragraph (1)(a) of Section 16.11.4.6, Determination of Counter-Party Available Credit Limits, at the time of the closure of the CRR bid submission window; or

(c) Pre-auction screening credit exposure amount, calculated in accordance with paragraph (2) of Section 7.5.5.3, Auction Process.

(4) ERCOT shall impose a credit limit in awarding bids and offers in the CRR Auction as described in Section 7.5.5.3.

16.11.4.6.2 Credit Requirements for DAM Participation

(1) ERCOT shall impose a credit limit of the ACLD on each Counter-Party participating in the DAM.

(2) ERCOT shall impose the credit limit for DAM participation calculated in paragraph (1) above on the Counter-Party's QSEs and all Subordinate QSEs combined participation in the DAM as described in Section 4.4.10, Credit Requirement for DAM Bids and Offers.

(3) A new credit limit will be sent to each Counter-Party participating in the DAM daily.

16.11.4.7 Credit Monitoring and Management Reports

(1) ERCOT shall post twice each Business Day on the Market Information System (MIS) Certified Area each active Counter-Party's credit monitoring and management related reports as listed below. The first posting shall be made by 1200 and the second posting shall be made as close as reasonably possible to the close of the Business Day but no later than 2350. The reports listed in items (f) and (g) below are not required to be included in both first and second posting if the Counter-Party has no active CRR ownership. The reports listed in items (c), (d), (e), (f), and (g) below are not required to be included in the

second post if there are no changes to the underlying data. ERCOT shall post one set of these reports on the MIS Certified Area on each non-Business Day for which an ACL is sent.

(a) Available Credit Limit (ACL) Summary Report;

(b) Total Potential Exposure (TPE) Summary Report;

(c) Minimum Current Exposure (MCE) Summary Report;

(d) Estimate Aggregate Liability (EAL) Summary Report;

(e) Estimated Aggregate Liability (EAL) Detail Report;

(f) Future Credit Exposure for CRR PTP Obligations (FCEOBL) Summary Report; and

(g) Future Credit Exposure for CRR PTP Options (FCEOPT) Summary Report.

[NPRR1103: Insert item (h) below upon system implementation:]

(h) Securitization Credit Exposure Report.

(2) The reports listed in paragraph (1) above will be posted to the MIS Certified Area in Portable Document File (PDF) format and Microsoft Excel (XLS) format. There shall be a provision to “open”, “save” and “print” each report.

16.11.5 Monitoring of a Counter-Party’s Creditworthiness and Credit Exposure by ERCOT

(1) ERCOT shall monitor the creditworthiness and credit exposure of each Counter-Party or its guarantor, if any. To enable ERCOT to monitor creditworthiness, each Counter-Party shall provide to ERCOT:

(a) Its own or its guarantor’s quarterly (semi-annually, if the guarantor is foreign and rated by a rating agency acceptable to ERCOT) unaudited financial statements not later than 60 days (90 days if the guarantor is foreign and rated by a rating agency acceptable to ERCOT) after the close of each of the issuer’s fiscal quarters; if an issuer’s financial statements are publicly available electronically and the issuer provides to ERCOT sufficient information to access those financial statements, then the issuer is considered to have met this requirement.

(b) Its own or its guarantor’s annual audited financial statements not later than 120 days after the close of each of the issuer’s fiscal year; if an issuer’s financial statements are publicly available electronically and the issuer provides to ERCOT sufficient information to access those financial statements, then the issuer is considered to have met this requirement. ERCOT may extend the period for providing interim unaudited or annual audited statements on a case-by-case basis. Annual audited financial statements must be prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP) or International Accounting Standards (IAS).

(c) For paragraphs (a) and (b) above, financial statements shall include the Counter-Party's or its guarantor's:

(i) Statement of Financial Position (balance sheet) as of the applicable quarterly or annual ending date;

(ii) Statement of Income (or Profit and Loss); and

(iii) Statement of Cash Flows.

(d) Notice of a material change. A Counter-Party that has been granted an Unsecured Credit Limit pursuant to Section 16.11.2, Requirements for Setting a Counter-Party's Unsecured Credit Limit, shall inform ERCOT within one Business Day if it has experienced a material change in its operations, financial condition or prospects that might adversely affect the Counter-Party and require a revision to its Unsecured Credit Limit. ERCOT may require the Counter-Party to meet one of the credit requirements of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

(2) A Counter-Party is responsible at all times for maintaining:

(a) Secured Collateral in an amount equal to or greater than that Counter-Party's

(i) TPES; plus

(ii) Net Positive Exposure of approved CRR Bilateral Trades; plus

(iii) ACL locked for CRR Auction, if any; and

(b) Remainder Collateral plus Financial Security defined as guarantees in paragraph (a) of Section 16.11.3 in an amount equal to or greater than that Counter-Party's

(i) TPEA; minus

(ii) Unsecured Credit Limit.

(3) ERCOT shall promptly notify each Counter-Party of the need to increase its Financial Security, including whether Secured Collateral must be provided, and allow the Counter-Party time, as defined in paragraph (6)(a) below, to provide additional Financial Security to maintain compliance with this Section.

(4) When either the Counter-Party's TPEA or TPES as defined in Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure, reaches 90% of its

requirement, ERCOT shall use reasonable efforts to electronically issue a warning to the Counter-Party's Authorized Representative and credit contact advising the Counter-Party that it should consider increasing its Financial Security. However, failure to issue that warning does not prevent ERCOT from exercising any of its other rights under this Section.

(5) ERCOT may suspend a Counter-Party when:

(a) That Counter-Party's TPES as defined in Section 16.11.4, equals or exceeds 100% of its Secured Collateral; or

(b) That Counter-Party's TPEA as defined in Section 16.11.4 equals or exceeds 100% of the sum of its Unsecured Credit Limit and its Remainder Collateral.

The Counter-Party is responsible at all times for managing its activity within both its TPEA and its TPES or increasing its Financial Security to avoid reaching its limits. Any failure by ERCOT to send a Notice as set forth in this Section does not relieve the Counter-Party from the obligation to maintain appropriate Financial Security in amounts equal to or greater than that Counter-Party's TPES and TPEA as defined in Section 16.11.4.

(6) To the extent that a Counter-Party fails to maintain Secured Collateral in amounts equal to or greater than its TPES or Remainder Collateral in amounts equal to or greater than its TPEA, each as defined in Section 16.11.4:

(a) ERCOT shall promptly notify the Counter-Party of the amount by which its Financial Security must be increased, including whether Secured Collateral must be provided and allow it:

(i) Until 1500 on the second Bank Business Day from the date on which ERCOT delivered the Notice to increase its Financial Security if ERCOT delivered its Notice before 1500; or

(ii) Until 1700 on the second Bank Business Day from the date on which ERCOT delivered Notification to increase its Financial Security if ERCOT delivered its Notice after 1500 but prior to 1700.

ERCOT shall notify the QSE's Authorized Representative(s) and Credit Contact if it has not received the required security by 1530 on the Bank Business Day on which the security was due; however, failure to notify the Counter-Party's representatives or contact that the required security was not received does not prevent ERCOT from exercising any of its other rights under this Section.

(b) At the same time ERCOT notifies the Counter-Party that is the QSE, ERCOT may notify each LSE and Resource represented by the Counter-Party that the LSE or Resource may be required to designate a new QSE if its current QSE fails to increase its Financial Security.

(c) ERCOT is not required to make any payment to that Counter-Party unless and until the Counter-Party increases its Financial Security, including any Secured Collateral required. The payments that ERCOT will not make to a Counter-Party include Invoice receipts, CRR revenues, CRR credits, reimbursements for short payments, and any other reimbursements or credits under any other agreement between the Market Participant and ERCOT. ERCOT may retain all such amounts until the Counter-Party has fully discharged all payment obligations owed to ERCOT under the Counter-Party Agreement, other agreements, and these Protocols.

(d) ERCOT may reject any bids or offers in a CRR Auction from the Counter-Party until it has increased its Financial Security, including any Secured Collateral required. ERCOT may reject any bids or offers from the Counter-Party in the DAM until it has increased its Financial Security.

(7) If a Counter-Party increases its Financial Security as required by ERCOT by the deadline in paragraph (6)(a) above, then ERCOT may notify each LSE and Resource represented by the Counter-Party.

(8) If a Counter-Party increases its Financial Security as required by ERCOT by the deadline in paragraph (6)(a) above, then ERCOT shall release any payments held.

[NPRR1112: Replace Section 16.11.5 above with the following upon system implementation and October 1, 2023:]

16.11.5 Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT

(1) ERCOT shall monitor the creditworthiness and credit exposure of each Counter-Party or its guarantor, if any. To enable ERCOT to monitor creditworthiness, each Counter-Party shall provide to ERCOT:

(a) Its own or its guarantor's quarterly (semi-annually, if the guarantor is foreign and rated by a rating agency acceptable to ERCOT) unaudited financial statements not later than 60 days (90 days if the guarantor is foreign and rated by a rating agency acceptable to ERCOT) after the close of each of the issuer's fiscal quarters; if an issuer's financial statements are publicly available electronically and the issuer provides to ERCOT sufficient information to access those financial statements, then the issuer is considered to have met this requirement.

(b) Its own or its guarantor's annual audited financial statements not later than 120 days after the close of each of the issuer's fiscal year; if an issuer's financial statements are publicly available electronically and the issuer provides to ERCOT sufficient information to access those financial statements, then the issuer is considered to have met this requirement. ERCOT may extend the period for providing interim unaudited or annual audited statements on a case-by-case basis. Annual audited financial statements must be prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP) or International Accounting Standards (IAS).

(c) For paragraphs (a) and (b) above, financial statements shall include the Counter-Party's or its guarantor's:

(i) Statement of Financial Position (balance sheet) as of the applicable quarterly or annual ending date;

(ii) Statement of Income (or Profit and Loss); and

(iii) Statement of Cash Flows.

(d) Notice of a material change. A Counter-Party shall inform ERCOT within one Business Day if it has experienced a material change in its operations, financial condition or prospects that might adversely affect the Counter-Party

(e) Any guarantor of a Counter-Party that submits its own financial statements pursuant to this section must provide a guarantee in one of the standard form documents approved by the ERCOT Board of Directors and be approved by ERCOT. No modifications of such forms are permitted.

(2) A Counter-Party is responsible at all times for maintaining:

(a) Financial Security in an amount equal to or greater than that Counter-Party's

(i) TPES; plus

(ii) Net Positive Exposure of approved CRR Bilateral Trades; plus

(iii) ACL locked for CRR Auction, if any; and

(b) Remainder Collateral in an amount equal to or greater than that Counter-Party's TPEA.

(3) ERCOT shall promptly notify each Counter-Party of the need to increase its Financial Security and allow the Counter-Party time, as defined in paragraph (6)(a) below, to provide additional Financial Security to maintain compliance with this Section.

(4) When either the Counter-Party's TPEA or TPES as defined in Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure, reaches 90% of its requirement, ERCOT shall use reasonable efforts to electronically issue a warning to the Counter-Party's Authorized Representative and credit contact advising the Counter-Party that it should consider increasing its Financial Security. However, failure to issue that warning does not prevent ERCOT from exercising any of its other rights under this Section.

(5) ERCOT may suspend a Counter-Party when:

(a) That Counter-Party's TPES as defined in Section 16.11.4, equals or exceeds 100% of its Financial Security; or

(b) That Counter-Party's TPEA as defined in Section 16.11.4 equals or exceeds 100% of its Remainder Collateral.

The Counter-Party is responsible at all times for managing its activity within both its TPEA and its TPES or increasing its Financial Security to avoid reaching its limits. Any failure by ERCOT to send a Notice as set forth in this Section does not relieve the Counter-Party from the obligation to maintain appropriate Financial Security in amounts equal to or greater than that Counter-Party's TPES and TPEA as defined in Section 16.11.4.

(6) To the extent that a Counter-Party fails to maintain Financial Security in amounts equal to or greater than its TPES or Remainder Collateral in amounts equal to or greater than its TPEA, each as defined in Section 16.11.4:

(a) ERCOT shall promptly notify the Counter-Party of the amount by which its Financial Security must be increased and allow it:

(i) Until 1500 on the second Bank Business Day from the date on which ERCOT delivered the Notice to increase its Financial Security if ERCOT delivered its Notice before 1500; or

(ii) Until 1700 on the second Bank Business Day from the date on which ERCOT delivered Notification to increase its Financial Security if ERCOT delivered its Notice after 1500 but prior to 1700.

ERCOT shall notify the QSE's Authorized Representative(s) and Credit Contact if it has not received the required security by 1530 on the Bank Business Day on which the security was due; however, failure to notify the Counter-Party's representatives or contact that the required security was not received does not prevent ERCOT from exercising any of its other rights under this Section.

(b) At the same time ERCOT notifies the Counter-Party that is the QSE, ERCOT may notify each LSE and Resource represented by the Counter-Party that the LSE or Resource may be required to designate a new QSE if its current QSE fails to increase its Financial Security.

(c) ERCOT is not required to make any payment to that Counter-Party unless and until the Counter-Party increases its Financial Security. The payments that ERCOT will not make to a Counter-Party include Invoice receipts, CRR revenues, CRR credits, reimbursements for short payments, and any other reimbursements or credits under any other agreement between the Market Participant and ERCOT. ERCOT may retain all such amounts until the

Counter-Party has fully discharged all payment obligations owed to ERCOT under the Counter-Party Agreement, other agreements, and these Protocols.

(d) ERCOT may reject any bids or offers in a CRR Auction from the Counter-Party until it has increased its Financial Security. ERCOT may reject any bids or offers from the Counter-Party in the DAM until it has increased its Financial Security.

(7) If a Counter-Party increases its Financial Security as required by ERCOT by the deadline in paragraph (6)(a) above, then ERCOT may notify each LSE and Resource represented by the Counter-Party.

(8) If a Counter-Party increases its Financial Security as required by ERCOT by the deadline in paragraph (6)(a) above, then ERCOT shall release any payments held.

16.11.6 Payment Breach and Late Payments by Market Participants

(1) It is the sole responsibility of each Market Participant to ensure that the full amounts due to ERCOT, or its designee, if applicable, by that Market Participant, are paid to ERCOT by the applicable time and date specified in the Protocols. If no time is specified in the Protocols for a particular type of payment, then payment must be made by the close of the Bank Business Day on which payment is due.

(2) If a Market Participant receives separate Invoices for Subordinate QSE or various CRR Account Holder activity, netting by the Market Participant of the amounts due to ERCOT with amounts due to the Market Participant among those Invoices for payment purposes is not permitted. The amounts due to ERCOT on the separate Invoices for each Market Participant must be paid by the applicable time and date specified in the Protocols. If a Market Participant does not pay the full amount due to ERCOT for all such Invoices by the required time, ERCOT shall deduct any and all amounts due and unpaid from any amounts due to the same Market Participant before allocating short payments to other Market Participants.

(3) The failure of a Market Participant to pay when due any payment or Financial Security obligation owed to ERCOT or its designee, if applicable, under any Agreement with ERCOT, is a Late Payment and constitutes an event of "Payment Breach." For purposes of designating a Late Payment, ERCOT shall consider multiple Invoices unpaid when due on a single Business Day by a single Market Participant as constituting one Late Payment. Any Payment Breach by a Market Participant under any agreement with ERCOT is a Default under all other agreements between ERCOT and the Market Participant unless cured within one Bank Business Day after ERCOT delivers to the Market Participant written notice of the Payment Breach.

(4) Upon a Payment Breach, ERCOT shall immediately attempt to contact the Market Participant's Authorized Representative and/or Credit Contact named in the Counter-Party Credit Application telephonically to inform the Market Participant of the Payment

Breach, and demand payment of the past due amount. ERCOT shall also provide the Market Participant with written notice of the Payment Breach via email. Upon a Payment Breach, ERCOT may impose remedies for Payment Breach, as set forth in Section 16.11.6.1, ERCOT's Remedies, in addition to any other rights or remedies ERCOT has under any agreement, these Protocols or at common law.

(5) If a Market Participant makes a payment (or a partial payment, if allowed by these Protocols) or satisfies a collateral call to ERCOT after the required due date and time, or if a short-paid Invoice is settled by a draw on available security greater than the amount of Market Participant's cash collateral held in excess of that required to cover its TPE ("Excess Collateral"), then that payment will be deemed a "Late Payment."

(6) For purposes of assessing if a payment is a Late Payment, the time of receipt of a payment will be determined as follows:

(a) For cash payments, the timestamp for when funds are credited to ERCOT's bank account, or;

(b) For non-cash Financial Security,

(i) The timestamp of the email or facsimile, if the required documentation is delivered to ERCOT by email or facsimile, or;

(ii) The timestamp of the delivery receipt, if the required documentation is mailed or physically delivered to ERCOT.

(7) ERCOT may, in its sole discretion, and upon a Market Participant's showing that the failure to pay when due was not within the control of the Market Participant, deem that a failure to pay when due was neither a Payment Breach nor a Late Payment.

(8) ERCOT shall track the number of Late Payments received from each Market Participant in each rolling 12-month period for purposes of imposing the Late Payment remedies set forth in Section 16.11.6.2, ERCOT's Remedies for Late Payments by a Market Participant.

16.11.6.1 ERCOT's Remedies

(1) In addition to all other remedies that ERCOT has under any agreement, common law or these Protocols, for Payment Breaches or other Defaults by a Market Participant, ERCOT has the following additional remedies.

16.11.6.1.1 No Payments by ERCOT to Market Participant

(1) ERCOT is not required to make any payment to a Market Participant unless and until the Market Participant satisfies the Payment Breach by paying the past due amount in full, including amounts due under Section 16.11.6.1.3, Aggregate Amount Owed by

Breaching Market Participant Immediately Due. The payments that ERCOT will not make include Invoice receipts, CRR Auction revenues, CRR credits, reimbursements for short payments and any other reimbursements or credits under any and all other agreements between ERCOT and the Market Participant. ERCOT shall retain all such amounts, and may apply all withheld funds toward the payment of the delinquent amount(s), until the Market Participant has fully paid all amounts owed to ERCOT under any agreements and these Protocols. If the Market Participant should fail to pay the full amount due within the cure period, ERCOT may apply all funds it withheld toward the payment of the delinquent amount(s).

16.11.6.1.2 ERCOT May Draw On, Hold or Distribute Funds

(1) Upon a Payment Breach, ERCOT, at its option, without notice to the Market Participant and in its sole discretion, may immediately, or at any time before the Market Participant pays the past due amount in full, including amounts due under Section 16.11.6.1.3, Aggregate Amount Owed by Breaching Market Participant Immediately Due, draw on, hold or distribute to other Market Participants any Financial Security or other funds of the Market Participant in ERCOT's possession. If the funds drawn exceed the amount applied to any Payment Breach, then ERCOT may hold those funds as Financial Security.

16.11.6.1.3 Aggregate Amount Owed by Breaching Market Participant Immediately Due

(1) ERCOT shall aggregate all amounts due it by the Market Participant under any agreement with ERCOT and these Protocols into a single amount to the fullest extent allowed by law. The entire unpaid net balance owed to ERCOT by the Market Participant, at ERCOT's option, and its sole discretion, is immediately due and payable without further notice and demand for payment. Any such notice and demand for payment are expressly waived by the Market Participant.

16.11.6.1.4 Repossession of CRRs by ERCOT

(1) ERCOT, at its sole discretion, may repossess CRRs held by a Market Participant with a Payment Breach or other Default. ERCOT shall effect that repossession by sending a written notice to the Market Participant of the repossession and by removing the CRRs from the Market Participant's CRR account. CRRs that settle in the same calendar month as the repossession but subsequent to the effective date of the repossession shall be voided. The Market Participant will neither be charged, nor entitled to credit, for the voided CRRs in the DAM Settlement. ERCOT shall offer a portfolio of CRRs containing all of the remaining unvoided repossessed CRRs, with each repossessed CRR in its existing configuration, in a one-time auction to Market Participants (other than the Market Participant(s) in Payment Breach or other Default) for sale to the highest bidder with a positive bid price for the entire portfolio. PTP Options with Refund and PTP Obligations with Refund will be voided and will not be included in the portfolio of repossessed CRRs available in the one-time auction. ERCOT shall offset net revenues from that sale against amounts owed to ERCOT by the Market Participant. If revenues

from the sale exceed amounts owed to ERCOT then the excess shall be remitted to the Market Participant. If ERCOT receives no positive bids for the portfolio of CRRs in the one-time auction, ERCOT shall void all of the repossessed CRRs.

[NPRR1023: Replace paragraph (1) above with the following upon system implementation:]

(1) ERCOT, at its sole discretion, may repossess CRRs held by a Market Participant in Default under an Agreement with ERCOT. ERCOT shall effect that repossession by sending a written notice to the Market Participant of the repossession and by removing the Market Participant's access to the repossessed CRRs. The repossessed CRRs will be handled as specified in Section 16.11.6.1.6, Liquidation of Repossessed or Forfeited CRRs.

16.11.6.1.5 Declaration of Forfeit of CRRs

(1) At ERCOT's sole discretion, if it does not receive full payment on the due date of a CRR Auction Invoice, may declare any of the CRR bids cleared and Pre-Assigned Congestion Revenue Rights (PCRRs) allocated to the Market Participant forfeited. ERCOT shall effect that forfeiture by sending a written notice to the Market Participant of the forfeiture and of not delivering the CRRs or PCRRs to the Market Participant's CRR account. ERCOT shall either (a) offer all forfeited CRRs, with each forfeited CRR in its existing configuration, in a one-time auction to Market Participants (other than the Market Participant(s) in Payment Breach or other Default) for sale to the highest bidder with a positive bid price or (b) ERCOT shall make the related capacity available in subsequent CRR Auctions. Revenue from that sale shall be considered as CRR Auction revenue and distributed to QSEs based on Load Ratio Share as specified in Section 7.5.7, Method for Distributing CRR Auction Revenues.

[NPRR1023: Replace paragraph (1) above with the following upon system implementation:]

(1) At ERCOT's sole discretion, if it does not receive full payment on the due date of a CRR Auction Invoice, it may declare any of the CRR bids cleared and Pre-Assigned Congestion Revenue Rights (PCRRs) allocated to the Market Participant forfeited. ERCOT shall effect that forfeiture by sending a written Notice to the Market Participant of the forfeiture and by not delivering the CRRs or PCRRs to the Market Participant's CRR account. The forfeited CRRs or PCRRs will be liquidated as specified in Section 16.11.6.1.6, Liquidation of Repossessed or Forfeited CRRs.

(2) ERCOT may also, at its sole discretion, honor any of the offers from Market Participants that were cleared in the CRR Auction by removing the CRRs from the Market Participant's CRR account. ERCOT shall offset net revenues due to the Market

Participant from CRRs offered and cleared against amounts owed to ERCOT by the Market Participant.

[NPRR1023: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT may also, at its sole discretion, honor any of the sell offers that were cleared in the CRR Auction made by a Market Participant who fails to fully pay the CRR Auction Invoice when due. ERCOT shall offset net revenues due to the Market Participant from CRRs offered and cleared against amounts owed to ERCOT by the Market Participant.

[NPRR1023: Insert Section 16.11.6.1.6 below upon system implementation and renumber accordingly:]

16.11.6.1.6 Liquidation of Repossessed or Forfeited CRRs

(1) If any repossessed or forfeited CRRs have the following characteristics, they will be irrevocably voided, the capacity will be dissolved, and they will not settle in the DAM beyond the effective date of the repossession or forfeiture nor be offered into any future CRR Auctions:

(a) PTP Options with Refund and PTP Obligations with Refund;

(b) Awarded PCRRs that have not yet been priced in a CRR Auction and paid for by the breaching or defaulting Market Participant; and

(c) Partial-month CRRs resulting from bilateral trades.

(2) The remaining unvoided CRRs in the repossessed or forfeited portfolio will be liquidated in the following manner, based on the characteristics of the CRRs:

(a) For CRRs that settle in the same month as the effective date of the repossession or forfeiture, for CRRs where the timing of the Market Participant Payment Breach or Default does not allow for the repossessed or forfeited CRRs to be offered into the CRR Monthly Auction in the calendar month following the Payment Breach or Default, for forfeited CRRs that were awarded in a CRR Monthly Auction, and for repossessed CRRs that have been offered into every available auction but were not fully awarded, the CRRs will settle in the DAM and may result in net payments or charges accruing for Operating Days throughout the month, as follows:

(i) If the CRR portfolio results in a net charge in the DAM, the payment will, to the extent possible, be made by drawing on any available Financial Security of the Market Participant from whom the CRRs were repossessed or forfeited. If this is insufficient to pay the charge in full, the remainder due will be short-paid for the Operating Day in accordance with Section 9.7.3, Enforcing the Financial Security of a Short-Paying Invoice Recipient. Regardless of the short pay, any Market Participant from whom CRRs were repossessed or forfeited shall remain liable for any charges associated with the liquidation of its CRRs in accordance with paragraph (4) of Section 16.11.6.1.7, Revocation of a Market Participant's Rights and Termination of Agreements.

(ii) If the CRR portfolio results in a net payment in the DAM, the payment amount will be added to the cash collateral held by ERCOT for the Market Participant from whom the CRRs were repossessed or forfeited.

(b) For any remaining unvoided repossessed or forfeited CRRs for one-month or multi-month strips, ERCOT will offer each CRR into the next available auction for the effective time period of the repossessed or forfeited CRR.

(i) CRRs will be offered into auctions at -$0.01 for PTP Options and -$500.00 for PTP Obligations.

(ii) If a CRR is offered into an auction but is not fully awarded, the remaining MW of the CRR will be offered into the next available auction for the effective time period of the repossessed or forfeited CRR. ERCOT may adjust the offer price for a PTP Obligation in subsequent auctions to increase the likelihood of the sell offer being fully awarded.

If another auction will not be held for the effective time period of the repossessed or forfeited CRRs, the remaining unawarded MW of each CRR will settle in the DAM and may result in net payments or charges accruing for Operating Days throughout the month, as noted in paragraph (2)(a) above.

(iii) Prior to offering repossessed or forfeited CRRs into an auction, ERCOT will calculate the value of all PTP Obligations for each CRR Account Holder associated with the defaulting Counter-Party by summing the value of all existing PTP Obligations for which the most recent auction clearing price for the effective time period of the auction was negative. The value of each CRR will be calculated per the following formula: (MW amount) x (TOU hours) x (auction clearing price). The total value of the PTP Obligations for the defaulting Counter-Party will be evaluated to determine if it exceeds 10% of the value of all existing PTP Obligations for which the most recent auction clearing prices for the effective time period of the auction were negative. If the total value of the PTP Obligations for the defaulting Counter-Party to be offered into an auction exceeds the 10% threshold, ERCOT will prorate the CRR

MW amounts to be offered into the auction to reduce the total portfolio value to be below the 10% threshold. The remaining CRR MW will be offered into the next available auction for the effective time period of the repossessed or forfeited CRRs or will settle in DAM if there will not be another auction for the effective time period.

(iv) A charge resulting from the sale of the CRRs into an auction will, to the extent possible, be paid by drawing on any available Financial Security of the Market Participant from whom the CRRs were repossessed or forfeited. If this is insufficient to pay the charge in full, the remainder due will be short-paid in accordance with Section 9.7.3. Regardless of the short pay, any Market Participant from whom CRRs were repossessed or forfeited shall remain liable for any charges associated with the liquidation of its CRRs in accordance with paragraph (4) of Section 16.11.6.1.7.

(v) A payment resulting from the sale of the CRRs into an auction will be added to the Financial Security of the Market Participant from whom the CRRs were repossessed or forfeited.

16.11.6.1.6 Revocation of a Market Participant's Rights and Termination of Agreements

(1) ERCOT may revoke a breaching Market Participant's rights to conduct activities under these Protocols. ERCOT may also terminate the breaching Market Participant's agreements with ERCOT.

(2) If ERCOT revokes a Market Participant's rights or terminates the Market Participant's agreements, then the provisions of Section 16.2.5, Suspended or Terminated Qualified Scheduling Entity – Notification to LSEs and Resource Entities Represented, and Section 16.2.6.1, Designation as an Emergency Qualified Scheduling Entity or Virtual Qualified Scheduling Entity, apply.

(3) If a breaching Market Participant is also an LSE (whether or not the Default occurred pursuant to the Market Participant's activities as an LSE), then:

(a) Within 24 hours of receiving notice of the Payment Breach, the Market Participant shall provide to ERCOT all the information regarding its ESI IDs set forth in the ERCOT Retail Market Guide; and

(b) On revocation of some or all of the Market Participant's rights or termination of the Market Participant's agreements and on notice to the Market Participant and the Public Utility Commission of Texas (PUCT), ERCOT shall initiate a Mass Transition of the Market Participant's ESI IDs pursuant to Section 15.1.3.1, Mass Transition Process, without the necessity of obtaining any order from or other action by the PUCT.

(4) After revocation of its rights or termination of its Agreement with ERCOT, the Market Participant will remain liable for all charges or costs associated with any continued activity related to the Counter-Party's relationship with ERCOT and any expenses arising from the consequences of such termination or revocation.

16.11.6.2 ERCOT's Remedies for Late Payments by a Market Participant

(1) If a Market Participant makes any Late Payments, and even if ERCOT does not immediately implement the above-referenced remedies for any Payment Breach by a Market Participant, the Market Participant is subject to the actions enumerated in this Section.

(2) This Section does not waive ERCOT's right to impose remedies for Payment Breach, as set forth in Section 16.11.6.1, ERCOT's Remedies, in addition to any other rights or remedies ERCOT has under any agreement, these Protocols, or at common law, for any Payment Breach by the Market Participant in each rolling 12-month period for purposes of imposing the Late Payment remedies set forth in this Section.

16.11.6.2.1 First Late Payment in Any Rolling 12-Month Period

(1) For the first Late Payment in any rolling 12-month period, ERCOT shall take Level I Enforcement action, as described in Section 16.11.6.2.5, Level I Enforcement.

(2) ERCOT shall send written notice to the Market Participant's Authorized Representative and/or Credit Contact via email, advising the Market Participant of the action required under Level I Enforcement.

16.11.6.2.2 Second Late Payment in Any Rolling 12-Month Period

(1) For the second Late Payment in any rolling 12-month period, ERCOT shall take Level II Enforcement action, as described in Section 16.11.6.2.6, Level II Enforcement.:

(2) ERCOT shall send written notice to the Market Participant's Authorized Representative and/or Credit Contact via email, advising the Market Participant of the action required under Level II Enforcement.

16.11.6.2.3 Third Late Payment in Any Rolling 12-Month Period

(1) For the third Late Payment in any rolling 12-month period, ERCOT shall take Level III Enforcement action, as described in Section 16.11.6.2.7, Level III Enforcement.

(2) ERCOT shall send written notice to the Market Participant's Authorized Representative and/or Credit Contact via email, advising the Market Participant of the action required under Level III Enforcement, and informing the Market Participant that a fourth Late Payment in any rolling 12-month period shall result in ERCOT taking action under

Section 16.11.6.1.6, Revocation of a Market Participant’s Rights and Termination of Agreements.

16.11.6.2.4 Fourth Late Payment in Any Rolling 12-Month Period

(1) For the fourth Late Payment resulting from a Payment Breach in any rolling 12-month period, ERCOT shall take action under Section 16.11.6.1.6, Revocation of a Market Participant’s Rights and Termination of Agreements.

16.11.6.2.5 Level I Enforcement

(1) Under Level I Enforcement, ERCOT shall notify the Market Participant to comply with one of the following requirements:

(a) If the Market Participant has not provided Financial Security, the Market Participant shall now provide Financial Security, within two Bank Business Days, in an amount at or above 110% of the amount of the Market Participant’s TPE less the Unsecured Credit Limit; or any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

(b) If the Market Participant has already provided Financial Security, the Market Participant shall increase its Financial Security, within two Bank Business Days, to an amount at or above 110% of its TPE less the Unsecured Credit Limit or any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

[NPRR1112: Replace paragraph (1) above with the following upon system implementation and October 1, 2023:]

(1) Under Level I Enforcement, ERCOT shall notify the Market Participant to comply with one of the following requirements:

(a) If the Market Participant has not provided Financial Security, the Market Participant shall now provide Financial Security, within two Bank Business Days, in an amount at or above 110% of the amount of the Market Participant’s TPE; or any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

(b) If the Market Participant has already provided Financial Security, the Market Participant shall increase its Financial Security, within two Bank Business Days, to an amount at or above 110% of its TPE or any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

(2) Increased Financial Security requirements under this Section remain in effect for a minimum of 60 days and remain in effect thereafter until ERCOT, at its sole discretion, determines to reduce such Financial Security requirements to the normally applicable levels.

16.11.6.2.6 Level II Enforcement

(1) Under Level II Enforcement, ERCOT shall notify the Market Participant that the Market Participant shall provide Financial Security, within two Bank Business days, in the form of a cash deposit or letter of credit, as chosen by ERCOT at its sole discretion, at 115% of the Market Participant's TPE less the Unsecured Credit Limit or for any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region.

[NPRR1112: Replace paragraph (1) above with the following upon system implementation and October 1, 2023:]

(1) Under Level II Enforcement, ERCOT shall notify the Market Participant that the Market Participant shall provide Financial Security, within two Bank Business days, in the form of a cash deposit or letter of credit, as chosen by ERCOT at its sole discretion, at 115% of the Market Participant's TPE or for any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region.

(2) Increased Financial Security requirements under this Section remain in effect for a minimum of 60 days and remain in effect thereafter until ERCOT, at its sole discretion, determines to reduce such Financial Security requirements to the normally applicable levels.

16.11.6.2.7 Level III Enforcement

(1) Under Level III Enforcement, ERCOT shall notify the Market Participant that the Market Participant shall provide Financial Security within two Bank Business Days at 120% of the Market Participant's TPE less the Unsecured Credit Limit or for any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region. Required Financial Security in excess of TPE must be in the form of a cash deposit.

[NPRR1112: Replace paragraph (1) above with the following upon system implementation and October 1, 2023:]

(1) Under Level III Enforcement, ERCOT shall notify the Market Participant that the Market Participant shall provide Financial Security within two Bank Business Days at 120% of the Market Participant's TPE or for any other liability to ERCOT that the

Market Participant has or is expected to have for activity in the ERCOT Region. Required Financial Security in excess of TPE must be in the form of a cash deposit.

(2) Increased Financial Security requirements under this Section remain in effect for a minimum of 90 days and remain in effect thereafter until ERCOT, at its sole discretion, determines to reduce such Financial Security requirements to the normally applicable levels.

16.11.7 Release of Market Participant's Financial Security Requirement

(1) Following the termination of a Market Participant's Standard Form Market Participant Agreement, ERCOT shall retain Financial Security to cover potential future obligations of the terminated Market Participant. These obligations may include, but are not limited to, Resettlement Statements, Final or True-Up Settlements, and Default Uplift Invoices.

[NPRR1023: Replace paragraph (1) above with the following upon system implementation:]

(1) Following the termination of a Market Participant's Standard Form Market Participant Agreement, ERCOT shall retain Financial Security to cover potential future obligations of the terminated Market Participant. These obligations may include, but are not limited to, the Invoices associated with the liquidation of repossessed or forfeited CRRs, Resettlement Statements, Final or True-Up Settlements, and Default Uplift Invoices.

[NPRR1023: Insert paragraph (2) below upon system implementation and renumber accordingly:]

(2) Regardless of whether a Market Participant's Agreement with ERCOT has been terminated, ERCOT shall not return or release any Financial Security of a Market Participant from whom CRRs were repossessed or forfeited until all such repossessed or forfeited CRRs have been voided, settled in the DAM, or sold in a CRR Auction in accordance with Section 16.11.6.1.6, Liquidation of Repossessed or Forfeited CRRs, and all Invoices associated with the liquidation have been paid in full.

(2) Required Financial Security for potential future obligations of a terminated Market Participant will be the maximum of the Counter-Party's TPE, as applicable, or $5,000.

[NPRR1023: Replace paragraph (2) above with the following upon system implementation:]

(3) Except as specified in paragraph (2) above, required Financial Security for potential future obligations of a terminated Market Participant will be the maximum of the Counter-Party's TPE, as applicable, or $5,000.

(3) If a terminated Market Participant elects to withdraw non-cash Financial Security following termination, and ERCOT determines that Financial Security continues to be necessary to cover potential future obligations, then the terminated Market Participant must provide ERCOT with Cash Collateral in the amount determined by ERCOT under this section before ERCOT will return or release the non-cash Financial Security to the terminated Market Participant.

(4) Upon ERCOT's sole determination that no sums remain owed or are necessary to cover potential future obligations to ERCOT by the terminated Market Participant, ERCOT shall return or release any Financial Security held by ERCOT to the terminated Market Participant.

[NPRR1023: Insert Section 16.11.8 below upon system implementation and renumber accordingly:]

16.11.8 Conversion of Letters of Credit and Surety Bonds to Cash Collateral

(1) To facilitate Settlement of Market Participant Invoices arising in consequence of a Payment Breach or other Default by a Market Participant, including but not limited to those described in Section 16.11.6.1.4, Repossession of CRRs by ERCOT, Section 16.11.6.1.5, Declaration of Forfeit of CRRs, and Section 16.11.6.1.6, Liquidation of Repossessed or Forfeited CRRs, ERCOT may at its sole discretion initiate conversion of guarantees, letters of credit, or surety bonds held as Financial Security to cash collateral.

16.11.8 Acceleration

(1) Upon termination of a Market Participant's rights as a Market Participant and any other agreement(s) between ERCOT and the Market Participant, all sums owed to ERCOT are immediately accelerated and are immediately due and owing in full. At that time, ERCOT may immediately draw upon the Market Participant's Financial Security and shall use those funds to offset or recoup all amounts due to ERCOT.

16.12 User Security Administrator and Digital Certificates

(1) Each Market Participant is allowed access to certain ERCOT computer systems through the use of Digital Certificates upon execution of the Standard Form Market Participant Agreement (as provided for in Section 22, Attachment A, Standard Form Market

Participant Agreement), and completion of applicable registration and qualification requirements. Digital Certificates expire after one year.

(2) A User Security Administrator (USA) is responsible for managing the Market Participant's access to non-public ERCOT computer systems through Digital Certificates. A USA may also be responsible for managing the Market Participant's access to the online Resource Integration and Ongoing Operations ("RIOO") system, which does not require a Digital Certificate. Each Market Participant that will receive Digital Certificate(s) must, as part of the application for registration with ERCOT, designate an individual employee or authorized agent as its USA, and optionally, a backup USA. If a Market Participant has designated a backup USA and the primary USA fails to perform, or is unable to perform, the functions required of a USA, then the backup USA shall perform any and all functions required of the primary USA. The Market Participant is responsible for revising its USA list as the need arises. The Market Participant's USA is responsible for registering all Market Participant's Digital Certificate holders ("Certificate Holders") and administering the use of Digital Certificates on behalf of the Market Participant. ERCOT Critical Energy Infrastructure Information (ECEII) posted on the Market Information System (MIS) Secure or Certified Area may be accessed only by those individuals that are issued ECEII-eligible Digital Certificates. Each Market Participant that will receive Digital Certificates and having more than one ERCOT functional registration must designate a USA for each registration (which may be the same employee or authorized agent) and shall manage each registration separately for the purposes of this Section. Once the Market Participant completes registration requirements, ERCOT shall send the USA a copy of the Digital Certificate user guide.

(3) Only Market Participants registered 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), may be eligible to opt out of designating a USA and receiving Digital Certificates if the Market Participant demonstrates to ERCOT's satisfaction that it does not need a Digital Certificate to perform its obligations under the ERCOT Protocols, market guides, or other applicable rules.

(4) An eligible Market Participant that wishes to opt out of designating a USA and receiving Digital Certificates shall submit a request form, found on the ERCOT website, confirming its desire to opt out subject to ERCOT's review and approval. ERCOT will notify the requesting Market Participant of its approval or disapproval of the request within 14 Business Days. ERCOT may subsequently revoke, at its sole discretion, Market Participant's election to opt out if the Market Participant's lack of a Digital Certificate causes administrative burdens or reliability concerns. ERCOT will send notice of revocation to the Market Participant who will have ten Business Days to fill out a Notice of Change of Information (NCI) form (Section 23, Form E, Notice of Change of Information) and submit it to ERCOT. Once the NCI is submitted, the request for a Digital Certificate will be subject to the same requirements applicable to the processing of an initial request by a new Market Participant.

(5) Market Participants that have received approval from ERCOT to opt out of designating a USA and receiving Digital Certificates are not excused from obligations under the

ERCOT Protocols, other than the obligations required in this Section 16.12 regarding Digital Certificates. Market Participants who opt out shall still be required to submit the Digital Certificate Audit Attestation (DCAA) required by paragraph (2) of Section 16.12.3, Market Participant Audits of User Security Administrators and Digital Certificates, for the portion of the year, if any, during which they had a USA and Digital Certificate(s).

(6) A Market Participant that has been granted approval by ERCOT to opt out of designating a USA and receiving Digital Certificates will not have access to information that would ordinarily be retrievable with a Digital Certificate. A Market Participant that has been granted approval by ERCOT to opt out of designating a USA and receiving Digital Certificates may, at any time, cancel its opt-out status by submitting an NCI form (Section 23, Form E).

16.12.1 USA Responsibilities and Qualifications for Digital Certificate Holders

(1) The USA and the Market Participant are responsible for the following:

(a) Requesting Digital Certificates for authorized Certificate Holders (either persons or programmatic interfaces) that the USA has qualified through an appropriate screening process requiring confirmation that the Certificate Holder is an employee or authorized agent (including third parties) of the Market Participant. A Certificate Holder (including the USA) must be qualified as set forth below. The Market Participant shall be liable for ensuring that each of its Certificate Holder(s) meets the requirements of (i) – (v) below.

(i) For any employee or authorized agent receiving a Digital Certificate, the Market Participant shall confirm that the employee or authorized agent satisfies reasonable background review sufficient for employment or contract with the Market Participant so as to reasonably limit threat(s) to ERCOT's market or computer systems. The Market Participant may not request that Digital Certificates be issued to any employee or authorized agent that it determines, after reasonable background review, poses a threat to ERCOT's market or computer systems.

(ii) The Certificate Holder is aware of the rules and restrictions relating to the use of Digital Certificates.

(iii) The Certificate Holder is eligible to review and receive technology and software under applicable export control laws and regulations. ERCOT shall post links to such laws and regulations on the ERCOT website.

(iv) The Market Participant has conducted a reasonable review of the Certificate Holder and has confirmed that the Certificate Holder is not on any U.S. terrorist threat lists such as the Consolidated Screening List or the Federal Bureau of Investigation Most Wanted Terrorists List. ERCOT will post links to relevant lists on the ERCOT website.

(v) The Certificate Holder does not violate the conditions of use specified by the software vendor that provides the Digital Certificates for the Market Participant's use and provided to the Certificate Holder. ERCOT will post links to relevant conditions of use on the ERCOT website.

(b) Requesting revocation of Digital Certificates. The Market Participant or USA shall request revocation of Digital Certificates by proceeding with the ERCOT Digital Certificate revocation process as described in the Digital Certificate User Guide. The Market Participant or USA shall request revocation of a Digital Certificate under any of the following conditions:

(i) As soon as possible but no later than three Business Days after:

(A) A Certificate Holder ceases employment with the Market Participant; or

(B) The Market Participant becomes aware that a Certificate Holder is changing job functions (pursuant to a reasonable process for identifying when job function changes occur) so that the Certificate Holder no longer needs the Digital Certificate;

(ii) As soon as possible, but no later than five Business Days, after the Market Participant becomes aware (pursuant to a reasonable process for identifying violations) that the Certificate Holder has violated any of the following conditions of use of a Digital Certificate:

(A) Violating the requirements if any of paragraph (1)(a)(i) – (v) above;

(B) Using the Digital Certificate for any unauthorized purpose; or

(C) Allowing any person other than the Certificate Holder to use the Digital Certificate.

(c) Managing the level of access for each Certificate Holder by assigning and maintaining Digital Certificate roles for each authorized user in accordance with the process set forth in ERCOT's Digital Certificate user guide.

(d) Requesting annual renewal of Digital Certificates.

(e) If needed, issuing Digital Certificates for use by electronic systems not limited to servers.

(f) Maintaining the integrity of the administration of Digital Certificates through consistent, sound and reasonable business practices.

16.12.2 Requirements for Use of Digital Certificates

(1) Use of Digital Certificates must comply with the following:

(a) A Digital Certificate shall be used by only one individual and may not be shared. If multiple employees or authorized agents share a computer and each requires a Digital Certificate, the USA shall request separate Digital Certificates for each. Multiple Digital Certificates may be installed and managed on a single computer. ERCOT shall include instructions on how to manage multiple Digital Certificates in the Digital Certificate user guide.

(b) A Digital Certificate may not be traded or sold.

(c) Electronic equipment on which the Digital Certificate resides must be physically and electronically secured in a reasonable manner to prevent improper use of the Digital Certificate.

(d) The Market Participant is wholly responsible for any use of Digital Certificates issued by its USA.

16.12.3 Market Participant Audits of User Security Administrators and Digital Certificates

(1) During September of each year, each Market Participant that has been issued any Digital Certificates shall generate a list of its registered USA and Certificate Holders. The Market Participant, through its USA or another authorized third party, shall perform an audit by reviewing the list and noting any inconsistencies or instances of non-compliance (including, for example, any Certificate Holder that may have changed job functions and no longer requires the Digital Certificate). If the Market Participant or its USA or the authorized third party identifies discrepancies, the USA shall use the process for managing Digital Certificates as included in ERCOT's Digital Certificate user guide to rectify the discrepancy. The audit must, at a minimum confirm that:

(a) The Market Participant and each listed USA and Certificate Holder meet the applicable requirements of paragraph (1)(a) of Section 16.12.1, USA Responsibilities and Qualifications for Digital Certificate Holders, and are not subject to any of the conditions that would require revocation as described in paragraph (1)(b) of Section 16.12.1;

(b) Each listed USA and Certificate Holder is currently employed by or is an authorized agent contracted with the Market Participant;

(c) The Market Participant has verified that the listed USA is authorized to be the USA;

(d) Each Certificate Holder is authorized to retain and use the Digital Certificate; and

(e) Each listed Certificate Holder needs the Digital Certificate to perform his or her job functions.

(2) By October 1 of each year, a Market Participant shall submit to ERCOT a DCAA (as provided for in Section 23, Form L, Digital Certificate Audit Attestation) from an individual who: (a) is an officer, executive, or employee of the Market Participant or of an Affiliate of the Market Participant; and (b) has authority to bind the Market Participant. The attestation shall certify that:

(a) The Market Participant has complied with the requirements of the audit;

(b) The Market Participant has verified that all assigned Digital Certificates belong to Certificate Holders authorized by the Market Participant's USA. If the Certificate Holders no longer meet the criteria in paragraph (1)(a) of Section 16.12.1, the USA shall inform ERCOT as described in paragraph (1)(b) of Section 16.12.1 and note the findings in the response; and

(c) The USA and all Certificate Holders have been qualified through a reasonable screening process and background review required by paragraphs (1)(a)(i)-(v) of Section 16.12.1.

(3) If a Market Participant cannot comply with the October 1 deadline at the time this Section first applies to the Market Participant, the Market Participant shall request an extension of the deadline by providing ERCOT a written explanation of why it cannot meet the deadline. The explanation must include a plan and timeline for compliance not to exceed six months from the original deadline. ERCOT shall review that extension request and notify the Market Participant if the request is approved or denied. ERCOT may approve no more than one extension request per Market Participant.

(4) By December 1 of each year, ERCOT shall acknowledge receipt of each DCAA audit received and indicate whether any required information is missing from the DCAA.

16.12.4 ERCOT Audit - Consequences of Non-compliance

(1) ERCOT, or its designee, shall review the DCAA submitted under Section 16.12.3, Market Participant Audits of User Security Administrators and Digital Certificates, and may audit the Market Participant for compliance with the provisions of this Section 16.12, User Security Administrator and Digital Certificates. The Market Participant shall cooperate fully with ERCOT in such audits.

(2) On or about December 15 of each year, ERCOT shall report to the Public Utility Commission of Texas (PUCT) all Market Participants failing to properly perform and/or submit complete DCAA(s) as described in Section 16.12.3 or non-compliance with Section 16.12.3.

(3) ERCOT, after providing notice to the Market Participant and PUCT Staff, may disqualify the Market Participant's USA and/or revoke any or all Digital Certificates assigned to the Market Participant if:

(a) The Market Participant does not properly and timely perform the audit;

(b) ERCOT discovers non-compliance; or

(c) The Market Participant does not timely request revocation of its Digital Certificates for unauthorized Certificate Holders.

(4) ERCOT's decision to disqualify a Market Participant's USA or revoke a Market Participant's Digital Certificates as described above is subject to the following:

(a) A Market Participant's Digital Certificates may not be revoked unless the Market Participant is given a reasonable opportunity to work with ERCOT to resolve the reason for revocation;

(b) A Market Participant's USA may not be disqualified unless it is given a reasonable opportunity to authorize a new USA and assign new Digital Certificates as necessary to prevent disruption of the Market Participant's business; and

(c) A Market Participant may dispute ERCOT's decision to disqualify the Market Participant's USA and/or revoke its Digital Certificates through the Alternative Dispute Resolution (ADR) Procedure in accordance with Section 20, Alternative Dispute Resolution Procedure, and may appeal the result of the ADR process to the PUCT as provided in Section 20.

16.13 Registration of Emergency Response Service Resources

(1) An Emergency Response Service (ERS) Resource shall be deemed to have registered with ERCOT when its duly authorized Qualified Scheduling Entity (QSE) submits an offer on behalf of the Resource in accordance with Section 3.14.3.1, Emergency Response Service Procurement.

16.14 Termination of Access Privileges to Restricted Computer Systems and Control Systems

(1) All Market Participants and ERCOT are required to have processes in place to terminate access privileges, as soon as practicable, to Restricted Systems for any employee, consultant, or contractor, upon termination of employment or where access is no longer required.

(2) "Restricted Systems" include computer or control systems that are essential to the operation of Restricted Facilities.

(3) "Restricted Facilities" include Facilities and assets that support the reliable operation of the bulk ERCOT System (100 kV and above), such as but not limited to:

(a) Generation Resources;

(b) Transmission substations;

(c) Control/dispatch centers and backup control/dispatch centers related to items (a) and (b) above;

(d) Systems and Facilities critical to system restoration (including but not limited to Black Start generators and substations); and

(e) Systems and Facilities critical to automatic firm load shedding.

(4) Access privilege is defined to include computer and electronic access.

(5) Each Market Participant and ERCOT shall have internal controls in place to ensure these processes are reviewed at least on an annual basis.

(6) Each Market Participant and ERCOT are required to notify the compliance monitoring authority within two Business Days after the discovery of any incident where a terminated employee, contractor or employee of a contractor has accessed a Restricted System when access privileges have been or should have been revoked.

(7) Failure by a Market Participant or ERCOT to follow its processes that results in access to any Restricted Systems by any employee, consultant, contractor or affiliate after his or her termination will be considered a violation of these Protocols.

16.15 Registration of Independent Market Information System Registered Entity

(1) Each Entity intending to qualify to access ERCOT's Market Information System (MIS) Secure Area, independent of any other Market Participant role, shall register with ERCOT, including any applicable fees, designating Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as an Independent Market Information System Registered Entity (IMRE)), and execute a Standard Form Market Participant Agreement (as provided in Section 22, Attachment A, Standard Form Market Participant Agreement) prior to receiving a USA Digital Certificate for setting access to ERCOT's MIS Secure Area.

(2) Continued status as an IMRE is contingent upon compliance with all applicable requirements in these Protocols. ERCOT may suspend an IMRE's rights as a Market Participant when ERCOT reasonably determines that it is an appropriate remedy for the Entity's failure to satisfy any applicable requirement.

16.16 Additional Counter-Party Qualification Requirements

16.16.1 Counter-Party Criteria

(1) In order to participate in the ERCOT Real-Time, Day-Ahead and Congestion Revenue Right (CRR) markets, in addition to satisfying any other eligibility requirements set forth in the ERCOT Protocols, each Counter-Party must satisfy, and at all times remain in compliance with, the following requirements:

  (a) **Expertise in Markets**. All employees or agents transacting in ERCOT markets pursuant to the ERCOT Protocols have had appropriate training and/or experience and are qualified and authorized to transact on behalf of the Counter-Party.

  (b) **Market Operational Capabilities**. Counter-Party has appropriate market operating procedures and technical abilities to promptly and effectively respond to all ERCOT market communications.

  (c) **Allowable Contract Participants**. Each Counter-Party must be one of the following:

    (i) An "Appropriate Person" as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 6(c)(3)(A)-(J));

    (ii) An "Eligible Contract Participant," as defined in section 1a(18)(A) of the Commodity Exchange Act (7 U.S.C. § 1a(18)(A)) and in Commodity Futures Trading Commission (CFTC) regulation 1.3(m) (17 C.F.R. § 1.3(m)); or

    (iii) A "person who actively participates in the generation, transmission, or distribution of electric energy," as that term is defined in the CFTC's final exemption order (78 Fed. Reg. 19,879).

  ERCOT may request necessary information to verify compliance with this requirement.

  (d) **Capitalization**. Counter-Party, or an acceptable guarantor, shall maintain minimum capital as follows:

    (i) For a Counter-Party seeking authorization to participate or participating in all ERCOT markets:

      (A) $10 million in total assets; or

      (B) $1 million in:

        (1) Unencumbered assets for unrated Electric Cooperative (EC) and Municipal systems; or

(2) Tangible Net Worth for all other Entities.

(ii) For a Counter-Party seeking authorization to participate or participating in all ERCOT markets except for the CRR market:

(A) $5 million in total assets; or

(B) $500,000 in:

(1) Unencumbered assets for unrated EC and Municipal systems; or

(2) Tangible Net Worth for all other Entities.

(iii) To fulfill the capitalization requirements above, a Counter-Party must provide:

(A) Audited financial statements of the Counter-Party or its guarantor in accordance with Section 16.11, Financial Security for Counter-Parties; and

[NPRR1112: Replace paragraph (A) above with the following upon system implementation and October 1, 2023:]

(A) Audited financial statements of the Counter-Party or its guarantor in accordance with Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT; and

(B) If for a guarantor, a guarantee on one of the standard form documents approved by the ERCOT Board, for an amount no less than the minimum necessary to meet the capitalization requirements.

(iv) Regardless of whether the Counter-Party or an acceptable guarantor meets the capitalization criteria above, ERCOT may nevertheless require the Counter-Party to meet the capitalization criteria by posting an Independent Amount in the event that the Counter-Party or a guarantor has a material change that may adversely affect the Counter-Party's or an acceptable guarantor's financial condition in conjunction with or subsequent to the most recent audited annual or unaudited quarterly financial statements. The Counter-Party shall notify ERCOT within one day after a material adverse change has occurred. The final determination of a material adverse change is solely within ERCOT's discretion.

(v) In the event audited financial statements do not meet the capitalization requirements, or there has been a material adverse change in the financial condition of the Counter-Party or acceptable guarantor in conjunction with or subsequent to the most recent audited annual or unaudited quarterly financial statements, Counter-Party will provide an Independent Amount in the form and amount necessary to participate in the ERCOT markets as follows:

(A) For a Counter-Party seeking authorization to participate or participating in all ERCOT markets, $500,000 Independent Amount.

(B) For a Counter-Party seeking authorization to participate or participating in all ERCOT markets except for the CRR market, $200,000 Independent Amount.

(C) For purposes of assessment of the Independent Amount, ERCOT will deem a Counter-Party that is or is applying to be a CRR Account Holder as having a desire to participate in all ERCOT markets.

(D) Financial Security posted pursuant to this section is fully available to ERCOT in the event of the Counter-Party's Payment Breach.

(E) ERCOT shall add the Independent Amount to that Counter-Party's Total Potential Exposure Secured (TPES) pursuant to Section 16.11 and designate it as the Independent Amount. ERCOT will require Financial Security for the Independent Amount in the same way as it does for other TPES elements.

(F) Any non-payment of the Independent Amount is considered a Payment Breach pursuant to Section 16.11.6, Payment Breach and Late Payments by Market Participants. ERCOT may use any of the remedies provided in Section 16.11.6 to collect the Independent Amount for each Counter-Party.

(e) **Risk Management Capabilities**. Each Counter-Party shall maintain appropriate, comprehensive risk management capabilities with respect to the ERCOT markets in which the Counter-Party transacts or wishes to transact. ERCOT may review documentation supporting a Counter-Party's risk management framework as part of its processes for verifying the implementation of a Counter-Party's risk management framework as described in Section 16.16.3, Verification of Risk Management Framework.

16.16.2 Annual Certification

(1) Each Counter-Party must submit to ERCOT annually a notarized certificate, signed by an officer or executive with authority to bind the Counter-Party, in the form of Section 22, Attachment J, Annual Certification Form to Meet ERCOT Additional Minimum

Participation Requirements, certifying that the Counter-Party is in compliance with each of the Counter-Party criteria and agrees to procedures for verification of its risk management framework as described in Section 16.16.3, Verification of Risk Management Framework.

(2) The certificate must be received by ERCOT no later than 120 days after the close of the fiscal year of the Counter-Party or its guarantor. ERCOT may extend the period for providing the certificate on a case-by-case basis.

(3) For new entry Counter-Parties, the certificate must be received by ERCOT prior to participation in any ERCOT markets.

(4) A Counter-Party shall notify ERCOT within one day if it has experienced a material adverse change that would make its most recent annual certificate inaccurate.

16.16.3 Verification of Risk Management Framework

(1) ERCOT will periodically perform or cause to be performed procedures to assess the risk management framework of Counter-Parties, including its implementation.

(2) ERCOT may retain a third party either to assess the sufficiency of the Counter-Party's risk management framework or to provide guidance and advice as to what constitutes appropriate content with respect to generally accepted risk management practices in their respective markets, commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of risk taken by the Counter-Party.

(3) ERCOT shall, identify the nature and scope of generally accepted risk management practices in their respective markets by which Counter-Party risk management frameworks will be assessed. Key elements will include:

(a) The risk management framework is documented in a risk policy addressing market and credit risks that has been approved by a Counter-Party's risk management function which includes appropriate corporate persons or bodies that are independent of the Counter-Party's trading functions, such as a risk management committee, a designated risk officer, participant Counter-Party's board or board committee, or, if applicable, a board or committee of the Counter-Party's parent company.

(b) A Counter-Party maintains an organizational structure with clearly defined roles and responsibilities that clearly segregate trading and risk control functions.

(c) There is clarity of authority specifying the transactions into which traders are allowed to enter.

(d) A Counter-Party ensures that traders have adequate training and/or experience relative to their delegations of authority in systems and the markets in which they transact.

(e) As appropriate, a Counter-Party has risk limits in place to control risk exposures.

(f) A Counter-Party has reporting in place to ensure risks are adequately communicated throughout the organization.

(g) A Counter-Party has processes in place for independent confirmation of executed transactions.

(h) A Counter-Party performs a periodic valuation or mark-to-market of risk positions, as appropriate.

(4) The ERCOT Board may approve minimum standards under an Other Binding Document.

(5) Upon notice of being selected for verification, a Counter-Party will make available or submit to ERCOT, or a third party acting on ERCOT's behalf, such documentation as is necessary to provide evidence of the sufficiency and implementation of its risk management framework. Such information may include, but not be limited to, documents of the following nature: risk policies, organizational charts, Delegations of Authority, training records, risk limit structure, reporting frameworks, and relevant procedures, all in a level of detail acceptable to ERCOT. Along with such documentation, a Counter-Party will provide a written explanation to ERCOT or its agent of how its risk management framework conforms to the risk management standards noted above. Requested information and documents must be made available for review by ERCOT, or a third party acting on ERCOT's behalf, 30 days after Notice of the request. ERCOT will provide Counter-Party Notice of inadequate documentation and will give Counter-Party ten Business Days to correct the inadequacy. At ERCOT's sole discretion, these deadlines may be extended on a case-by-case basis.

(6) If necessary, Counter-Parties will support the verification process by, among other things, making appropriate personnel available for interviews, permitting on-site observation of credit and risk management processes and procedures, and providing written responses to written inquiries on a timely basis. A Counter-Party may request that ERCOT or a third party performing verification on ERCOT's behalf perform the review on-site at the Counter-Party's location. Any resulting additional expenses will in this case be the sole responsibility of the Counter-Party making the request.

(7) ERCOT will perform procedures to verify the risk management framework at least annually for any Counter-Party if that Counter-Party or its guarantor:

(a) Is ineligible for unsecured credit under Section 16.11.2, Requirements for Setting a Counter-Party's Unsecured Credit Limit; and

[NPRR1112: Replace paragraph (a) above with the following upon system implementation and October 1, 2023:]

(a) Has had one or more late payments or represents a Qualified Scheduling Entity (QSE) or CRR Account Holder that has short-paid Settlement Invoices in the year preceding the date of the annual certificate; and

(b) Has had exposure in CRR Obligations in the ERCOT CRR market during the year preceding the date of the annual certificate.

(i) Notwithstanding the above, ERCOT will perform risk management framework verification procedures on other Counter-Parties at its sole discretion.

(8) Upon completion of its review, ERCOT will notify the Counter-Party whether or not any material deficiencies were noted. If material deficiencies exist, ERCOT may, in its sole discretion, establish in consultation with the Counter-Party, a remediation plan for any deficiencies. The remediation period allowed for specific deficiencies should be consistent with the severity of those deficiencies and may have incremental deadlines. The total remediation period will not exceed 90 days, unless extended, at ERCOT's sole discretion, on a case-by-case basis.

(9) Risk management deficiencies remaining beyond the ERCOT-defined remediation periods constitute a material breach under the Counter-Party's Standard Form Market Participant Agreement as provided for in Section 22, Attachment A, Standard Form Market Participant Agreement. Upon a material breach, ERCOT may, in addition to any other rights or remedies ERCOT has under any agreement, these Protocols or at common law, suspend any or all future activities in the ERCOT market, pending remediation of deficiencies. An action by ERCOT to suspend activities in the ERCOT market is subject to the provisions of Section 20, Alternative Dispute Resolution Process.

(10) Participation in ERCOT markets is contingent on verification by ERCOT, or by a third party acting on ERCOT's behalf, that the proposed measures have been implemented.

(11) If a Counter-Party provides evidence that its risk management framework has been deemed sufficient for transacting in another Regional Transmission Operator/Independent System Operator market in the United States, ERCOT may elect to forego verification processes.

(12) In conjunction with providing its annual certificate, if a Counter-Party certifies that there has been no material change in its risk management capabilities since the framework was last verified, ERCOT may elect to forego verification. ERCOT may not forego verification more than once in any 24-month period.

16.17 Exemption for Qualified Scheduling Entities Participating Only in Emergency Response Service

(1) A Qualified Scheduling Entity (QSE) that is not also registered as a Congestion Revenue Rights (CRR) Account Holder, that does not participate in the Day-Ahead Market (DAM) or Real-Time Market (RTM), that represents only Emergency Response Service (ERS) Resources, and whose Total Potential Exposure (TPE) (as calculated in Section 16.11.4.1, Determination of Total Potential Exposure for a Counter-Party) is zero may request designation as an ERS-only QSE.

(2) A QSE must submit a written request for designation as an ERS-only QSE at least five Business Days before the desired effective date of the designation.

(3) Upon determining that the QSE has addressed all financial risk to ERCOT's satisfaction, ERCOT shall designate the QSE as an ERS-only QSE, and shall notify the QSE of that designation in writing.

(4) Except as provided in paragraph (5) below, an ERS-only QSE is exempt from the following requirements:

(a) The requirement to maintain sufficient collateral under Sections 16.11.1, ERCOT Creditworthiness Requirements for Counter-Parties, and 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT;

(b) The requirement to submit financial statements and any notice of material changes under paragraph (1) of Section 16.11.5; and

(c) All requirements under Section 16.16, Additional Counter-Party Qualification Requirements.

(5) If ERCOT posts an RTM True-Up Statement or RTM Resettlement Statement providing for a resettlement of any ERS Time Period, and as a result of that resettlement alone, ERCOT determines that an ERS-only QSE has a positive TPE as calculated in Section 16.11.4.1, ERCOT will require that QSE to comply with Section 16.11.5, excluding paragraph (1), until its TPE again equals zero. If the QSE fails to pay when due any payment or Financial Security obligation owed to ERCOT, ERCOT may terminate the QSE's ERS-only status.

(6) ERCOT shall ensure that its systems prevent participation by ERS-only QSEs in the DAM and RTM.

(7) A QSE must request termination of its ERS-only status in writing. Termination of ERS-only status will be effective only upon ERCOT's written confirmation that the QSE has satisfied all creditworthiness and capitalization requirements applicable to QSEs.

(8) Nothing in this Section affects an ERS-only QSE's obligation under paragraph (5) of Section 16.2.1, Criteria for Qualification as a Qualified Scheduling Entity, to provide ERCOT notice of any material change that could adversely affect the reliability or safety

of the ERCOT System. Additionally, ERCOT may at any time require any ERS-only QSE to demonstrate that its risk management policies and practices are sufficient to ensure that it will be capable of meeting its ERS performance requirements during any ERS Standard Contract Term for which it has submitted an offer or for which it is committed to provide ERS.

[NPRR857: Insert Section 16.18 below upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities; and renumber accordingly:]

16.18 Registration of a Direct Current Tie Operator

(1) Each Entity that operates a Direct Current Tie (DC Tie) shall register as a Direct Current Tie Operator (DCTO) with ERCOT. To register as a DCTO, an Entity must execute a Standard Form Market Participant Agreement (using the form provided in Section 22, Attachment A, Standard Form Market Participant Agreement), designate a DCTO Authorized Representative and contacts, confirm that it is either registered with ERCOT as a Transmission Service Provider (TSP) that is subject to a Public Utility Commission of Texas (PUCT)-approved code of conduct or is subject to Federal Energy Regulatory Commission (FERC)-approved standards of conduct, and be capable of performing the functions of a DCTO, as applicable, as described in these Protocols.

16.18 Cybersecurity Incident Notification

(1) Each Market Participant shall designate and maintain a Cybersecurity Contact for communications with ERCOT with respect to Cybersecurity Incidents. Registered Market Participants shall use the Notice of Change of Information form, as provided for in Section 23, Form E, Notice of Change of Information, to designate a Cybersecurity Contact, and maintain updated Cybersecurity Contact information.

(2) As soon as practicable upon determination of a Cybersecurity Incident on a Market Participant's computer network or system that interfaces with an ERCOT computer network or system, the Market Participant shall notify ERCOT.

(3) For purposes of this section, in the event a Market Participant delegates authority to an agent, the Market Participant shall ensure that the agent is obligated to notify the Market Participant, as soon as practicable, upon the agent's discovery of a Cybersecurity Incident on the agent's computer network or system that interfaces with an ERCOT computer network or system.

(4) A Market Participant shall notify ERCOT, as soon as practicable, upon the agent's notification to the Market Participant of a Cybersecurity Incident on the agent's computer network or system that interfaces with an ERCOT computer network or system for the purpose of transacting with ERCOT on behalf of the Market Participant. If a Market Participant's agent is also registered with ERCOT as a Market Participant, only the agent is required to report a Cybersecurity Incident on its computer network or system that interfaces with an ERCOT computer network or system to ERCOT. The failure of an agent to notify the Market Participant of a Cybersecurity Incident shall not constitute a violation of this section if the Market Participant can demonstrate that a reporting mandate exists in a contract between the Market Participant and its agent.

(5) In order to notify ERCOT of a Cybersecurity Incident, Market Participants shall submit a Notice of Cybersecurity Incident (Section 23, Form O, Notice of Cybersecurity Incident) to NCSI@ercot.com. If, as a result of the Cybersecurity Incident, a Market Participant is unable to securely send the Notice of Cybersecurity Incident to ERCOT, the Market Participant shall call the ERCOT HelpDesk at (512) 248-6800 and/or its Client Service Representative to request a secure means for sending the Notice of Cybersecurity Incident to ERCOT.

(a) A Market Participant may designate a temporary cybersecurity contact for a particular Cybersecurity Incident by providing contact information for such individual in the Notice of Cybersecurity Incident form submitted to ERCOT. Should a Market Participant designate a temporary cybersecurity contact in its Notice of Cybersecurity Incident, ERCOT will direct communications concerning that particular Cybersecurity Incident to the temporary cybersecurity contact.

(b) Following initial notification, Market Participant shall provide ERCOT with updated information concerning the Cybersecurity Incident as it becomes available, and upon ERCOT's request, until ERCOT provides notice to Market Participant that information regarding the Cybersecurity Incident is no longer needed. To the extent practicable, the Notice of Cybersecurity Incident form shall be used to provide ERCOT with updated information.

(6) In the event ERCOT determines that a Cybersecurity Incident may materially impact computer networks or systems of ERCOT and/or Market Participants, ERCOT shall issue a Market Notice to all Market Participants with general information concerning the Cybersecurity Incident. ERCOT may utilize the information contained in a Notice of Cybersecurity Incident, except that in no event shall the Market Notice contain information identifiable to a specific Market Participant or ERCOT Critical Energy Infrastructure Information (ECEII).

16.19 Designation of Transmission Operators

(1) Each Transmission Service Provider (TSP) shall either register as a Transmission Operator (TO) or designate one or more other Transmission and/or Distribution Service Providers (TDSPs) as its TO for each Transmission Facility owned by the TSP. Each

DSP shall either register as a TO or designate another TDSP as its TO. A TDSP shall designate another Entity as its TO only with the written consent of that other Entity.

(2) A TO shall have full authority to act on behalf of the designating TDSP in the performance of all TO responsibilities provided in the ERCOT Protocols or Other Binding Documents, including effectuating any Load-shed that may be necessary during any Energy Emergency Alert (EEA) event, Under-Frequency Load Shed (UFLS) event, or Under-Voltage Load Shed (UVLS) event.

(3) To qualify for designation as a TO, a TDSP shall be connected to the ERCOT Wide Area Network (WAN) and maintain 24-hour, seven-day-per-week operations and Hotline communications with ERCOT. A TO has a responsibility to answer each TO Hotline call.

(4) A TSP shall enter a TO designation for each Transmission Facility it owns in the Network Operations Model. Any designation or change to that designation shall be submitted to ERCOT within the time required for submitting physical changes to the Network Operations Model specified in paragraph (3) of Section 3.10.1, Time Line for Network Operations Model Changes. Any TSP designated as a TO for another TSP’s facilities may unilaterally reject or resign from that designation by providing written notice to the designating TSP and the TSP shall promptly update the TO designation in the Network Operations Model for the affected Transmission Facility.

(5) ERCOT shall post a Transmission Operator Designation Form on the ERCOT website. A Distribution Service Provider (DSP) may designate a TO or make any change to its designation, including revoking a TO designation, by properly completing the Transmission Operator Designation Form and submitting it via email to ERCOT with a copy provided to the TDSP designated as TO. Any such change shall be submitted to ERCOT at least 30 days before the change becomes effective. The designation of a TO shall not be effective unless the Transmission Operator Designation Form has been signed by an officer or other Authorized Representative of the designating DSP and the TDSP designated as TO.

(6) A TO for a DSP may unilaterally resign from a designation as TO by submitting a properly completed Transmission Operator Designation Form to ERCOT reflecting the TO’s resignation of its TO status at least 30 days before the resignation becomes effective. The resigning TO shall provide simultaneous notice of the resignation to the DSP it represents.

(7) On the effective date of a TO’s resignation, the DSP previously represented by the resigning TO shall be deemed its own TO and shall assume all TO responsibilities unless and until it has properly designated another TDSP as its TO.

[NPRR1045: Replace Section 16.19 above with the following upon system implementation of NPRR857:]

16.19 Designation of Transmission Operators

(1) Each Transmission Service Provider (TSP) shall either register as a Transmission Operator (TO) or designate one or more other Transmission and/or Distribution Service Providers (TDSPs) as its TO for each Transmission Facility owned by the TSP. Each Direct Current Tie Operator (DCTO) shall designate a TDSP as its TO for each DC Tie it operates. Each Distribution Service Provider (DSP) shall either register as a TO or designate another TDSP as its TO. A TDSP or DCTO shall designate another Entity as its TO only with the written consent of that other Entity.

(2) A TO shall have full authority to act on behalf of the designating TDSP or DCTO in the performance of all TO responsibilities provided in the ERCOT Protocols or Other Binding Documents, including effectuating any Load-shed that may be necessary during any Energy Emergency Alert (EEA) event, Under-Frequency Load Shed (UFLS) event, or Under-Voltage Load Shed (UVLS) event.

(3) To qualify for designation as a TO, a TDSP shall be connected to the ERCOT Wide Area Network (WAN) and maintain 24-hour, seven-day-per-week operations and Hotline communications with ERCOT. A TO has a responsibility to answer each TO Hotline call.

(4) A TSP or DCTO shall enter a TO designation for each Transmission Facility it owns in the Network Operations Model. Any designation or change to that designation shall be submitted to ERCOT within the time required for submitting physical changes to the Network Operations Model specified in paragraph (3) of Section 3.10.1, Time Line for Network Operations Model Changes. Any TSP designated as a TO for another TSP or DCTO’s facilities may unilaterally reject or resign from that designation by providing written notice to the designating TSP and the TSP shall promptly update the TO designation in the Network Operations Model for the affected Transmission Facility.

(5) ERCOT shall post a Transmission Operator Designation Form on the ERCOT website. A DSP may designate a TO or make any change to its designation, including revoking a TO designation, by properly completing the Transmission Operator Designation Form and submitting it via email to ERCOT with a copy provided to the TDSP designated as TO. Any such change shall be submitted to ERCOT at least 30 days before the change becomes effective. The designation of a TO shall not be effective unless the Transmission Operator Designation Form has been signed by an officer or other Authorized Representative of the designating DSP or DCTO and the TDSP designated as TO.

(6) A TO for a DSP may unilaterally resign from a designation as TO by submitting a properly completed Transmission Operator Designation Form to ERCOT reflecting the TO’s resignation of its TO status at least 30 days before the resignation becomes effective. The resigning TO shall provide simultaneous notice of the resignation to the DSP it represents.

(7) On the effective date of a TO's resignation, the DSP previously represented by the resigning TO shall be deemed its own TO and shall assume all TO responsibilities unless and until it has properly designated another TDSP as its TO.

ERCOT Nodal Protocols

Section 17: Market Monitoring and Data Collection

June 1, 2021

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17 MARKET MONITORING AND DATA COLLECTION

17.1 Overview

(1) The Public Utility Commission of Texas (PUCT), with the assistance of the Independent Market Monitor (IMM) established in accordance with PUCT rules, has the ultimate responsibility for market oversight in ERCOT. ERCOT shall assist the PUCT and the IMM by performing the data collection functions specified in this Section.

17.2 Objectives and Scope of Market Monitoring Data Collection

(1) The market monitoring data collection is designed to assist the Public Utility Commission of Texas (PUCT) and Independent Market Monitor (IMM) to:

(a) Protect Market Participants and Customers from the exercise of market power and from market manipulations;

(b) Ensure that there is effective and persistent competition for events that are not mitigated;

(c) Ensure that the market design and implementation are efficient;

(d) Guard against inefficiencies in the market and market manipulations;

(e) Ensure a justifiable and reasonable price impact; and

(f) Ensure that data posted on the ERCOT website fulfills the objective of transparency of market information consistent with Section 1.3, Confidentiality.

17.3 Market Data Collection and Use

(1) ERCOT shall establish procedures to ensure that the Public Utility Commission of Texas (PUCT) Staff and Independent Market Monitor (IMM) may access all data maintained by ERCOT and deemed necessary by the PUCT staff and IMM to perform its market oversight activities, pursuant to subsection (e) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance. The following sections explain the collection, handling, verification, and retention of information by ERCOT that is accessible by the PUCT Staff and IMM.

17.3.1 Information System Data Collection and Retention

(1) ERCOT shall develop and operate an information system to collect and to store data required by these Protocols. ERCOT shall provide adequate communication equipment and necessary software packages to enable the PUCT Staff and the IMM to establish electronic access to the information system and to facilitate the development and

application of quantitative tools necessary for the market monitoring function. Data from source systems must be replicated near Real-Time and available for remote query by the PUCT Staff and the IMM until data is available in the Data Archive and Data Warehouse. The Data Warehouse and Data Archive must be designed to accommodate a remote query function by the PUCT Staff and the IMM at any time.

17.3.2 Data Categories and Handling Procedures

(1) ERCOT shall develop, and refine based on experience, a detailed catalog of all data categories that it can acquire and the procedures that it will use to handle such data, including procedures for protecting Protected Information and ERCOT Critical Energy Infrastructure Information (ECEII). This catalog must include documentation of the meaning of the data elements, and must be updated upon any change in systems (e.g. Energy and Market Management System (EMMS) or Settlements) that affect the data elements or interpretation of these elements.

17.3.3 Accuracy of Data Collection

(1) ERCOT shall continuously apply appropriate procedures for the accurate collection of data into the Data Warehouse and accurate communication of that data for use by the PUCT Staff and IMM. By written notice, ERCOT may require Market Participants to verify the accuracy of data previously submitted to ERCOT.

(2) ERCOT shall report to the PUCT and IMM any failure by a Market Participant to provide accurate and complete information in the manner and time requested under these Protocols, and that failure may be treated as grounds for action against the Market Participant.

(3) ERCOT shall cause to be performed an audit on a periodic basis no less than once every three years of ERCOT data, data collection, and data documentation for adequacy and accuracy. The auditor will provide recommendations to address potential areas of improvements.

17.3.4 PUCT Staff and IMM Review of Data Collection

(1) The PUCT Staff and IMM may review the catalogs of information and data collection verification criteria, developed by ERCOT according to these Protocols, and may propose such changes, additions, or deletions to the catalogs and criteria as it sees fit. In so doing, the PUCT Staff or IMM may require database items or evaluation criteria to be included in the pertinent catalogs.

17.3.5 Data Retention

(1) Data stored in the Data Warehouse and Data Archive must be available online for four years from ERCOT's creation or receipt of the data. Data stored in the Data Archive must be maintained by ERCOT for a total of seven years from ERCOT's creation or receipt of the data.

17.4 Provision of Data to Individual Market Participants

(1) Data requested by a Market Participant that is not available to the requesting Market Participant via the Market Information System (MIS) may be provided by ERCOT to the requesting Market Participant subject to constraints on ERCOT's resources and applicable restrictions on Protected Information and ERCOT Critical Energy Infrastructure Information (ECEII), but this Section is not an authorization to release Protected Information or ECEII of other Entities. ERCOT shall accommodate these requests on a nondiscriminatory basis.

17.5 Reports to PUCT Staff, IMM, and the FERC

(1) ERCOT shall make data available to the Public Utility Commission of Texas (PUCT) Staff and Independent Market Monitor (IMM). PUCT Staff or IMM may require, after consultation with ERCOT, changes to the form of the data, limited to data ERCOT is reasonably able to collect.

(2) ERCOT shall submit reports in accordance with its regulatory obligations under the applicable rules, laws, and orders of the PUCT and the Federal Energy Regulatory Commission (FERC).

17.6 Changes to Facilitate Market Operation

(1) ERCOT shall evaluate its system operation and market performance to identify potential areas for improvements. This evaluation must consider impacts on system operations and market performance of Public Utility Commission of Texas (PUCT) rules, these Protocols, Operating Guides, and any other ERCOT operating procedures. Upon identification of areas that require improvements, ERCOT shall take appropriate actions to make those improvements including revising its procedures, proposing changes to these Protocols through the process specified in Section 21, Revision Request Process, and submitting recommendations to the PUCT or other appropriate Governmental Authorities. In performing these tasks, ERCOT shall seek comments and recommendations from the Independent Market Monitor (IMM), PUCT Staff, Market Participants, and other interested Entities.

ERCOT Nodal Protocols

Section 18: Load Profiling

April 1, 2022

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18 LOAD PROFILING

18.1 Overview

(1) The ERCOT retail market requires a 15-minute Settlement Interval. Load Profiling provides a cost-effective way of estimating and allocating 15-minute Load for Electric Service Identifiers (ESI IDs). This Section details how Load Profiling will be implemented in ERCOT when ERCOT does not receive 15-minute Settlement Interval consumption data and enables the accounting of energy usage in the market Settlement process.

18.2 Methodology

(1) A Load Profiling Methodology is the fundamental basis on which Load Profiles are created. The implementation of a Load Profiling Methodology may require statistical Sampling, engineering methods, econometric modeling, or other approaches. All Load Profiles shall conform to the ERCOT-defined Settlement Interval length.

(2) ERCOT has developed Load Profiles for:

(a) Non-interval metered Loads;

(b) Non-Metered Loads; and

(c) Interval Data Recorders (IDRs) including:

(i) Advanced Meters; and

(ii) IDR Meters.

(3) The following Load Profiling Methodologies are used:

Type of Load	**Load Profiling Methodology**
Non-interval metered	Adjusted Static Models
Non-interval metered with Distributed Generation (DG)	Adjusted Static Models and engineering estimates
Non-metered	Engineering estimates

18.2.1 Guidelines for Development of Load Profiles

(1) In developing Load Profiles, ERCOT shall strive to achieve an optimal combination of the following:

(a) Give no unfair advantage to any Entity;

(b) Maximize usability by minimizing the total number of Load Profiles without compromising accuracy and cost effectiveness;

(c) Minimize the Load Profiles' contribution to Unaccounted For Energy (UFE) over all Settlement Intervals, paying particular attention to higher cost periods;

(d) Reflect reasonably homogenous groups, with respect to Load shape and likely supply costs;

(e) Develop Load Profiles that are distinctly different;

(f) Develop Load Profiles for areas with incomplete Load data utilizing data from other sources, taking into account similarities and differences in Load;

(g) Accommodate development of unique rate classes;

(h) Use the most accurate Load research data available; and

(i) Develop Load Profiles based on readily identifiable parameters that are not subject to frequent change.

18.2.2 Load Profiles for Non-Interval Metered Loads

18.2.2.1 Load Profiles for Non-Interval Metered Loads Without Distributed Generation

(1) Load Profiles for non-interval metered Loads are created using statistical models developed from appropriate Load research sample data. These models are referred to as adjusted static. These model equations relate daily Settlement Interval Load patterns to relevant weather descriptors such as maximum and minimum dry-bulb temperature and humidity. Other daily characteristics such as day-of-the-week and sunrise/sunset times are also employed.

18.2.2.2 Load Profiles for Non-Interval Metered Loads With Distributed Generation

(1) Load Profiles for non-interval metered Loads that utilize DG (e.g., PhotoVoltaic (PV) or wind) will be created using a hybrid approach. At least a portion of the Load Profile will be based on Adjusted Static Models, while engineering estimates and/or generation models may be integrated as well or otherwise utilized.

18.2.3 Load Profiles for Non-Metered Loads

(1) Load Profiles for Non-Metered Loads, e.g. streetlights, traffic signals, security lighting, billboards, and parking lots are created using engineering estimates based on known criteria, such as hours of operation, with appropriate variation in sunrise/sunset times. Transmission Service Providers (TSPs) and/or Distribution Service Providers (DSPs) are responsible for providing monthly consumption (kWh) for non-metered Electric Service Identifiers (ESI IDs).

18.2.4 Default Load Profiles for Interval Data Recorders

(1) Default Load Profiles for IDRs will only be used when no historic Customer-specific interval data is available for Settlements. The Adjusted Static Model methodology will be used to create these Load Profiles.

(2) For details on the method to estimate IDR data for Settlement purposes, refer to Section 11, Data Acquisition and Aggregation.

18.2.5 Identification of Weather Zones and Load Profile Types

(1) ERCOT, in coordination with the appropriate Technical Advisory Committee (TAC) subcommittee, will identify Weather Zones and Load Profile Types based on an analysis of Load data, weather data, and sunrise/sunset data.

18.2.6 Daily Profile Creation Process

(1) ERCOT will maintain Load Profile Models to create profiles for the target Settlement day (backcast) and three days following the current day (forecast). ERCOT will automatically collect actual weather conditions and weather forecasts to enable the creation of the Load Profiles. ERCOT will maintain sunrise/sunset information for creating Load Profiles that require these parameters.

18.2.7 Maintenance of the Load Profile Models

(1) Upon request from the appropriate TAC subcommittee, ERCOT shall review the validity and accuracy of the Load Profile Models. ERCOT shall make the necessary recommendation to alleviate any situations whereby Load Profiles are no longer representative.

18.2.8 Adjustments and Changes to Load Profile Development

(1) Any changes to the Load Profiling Methodology, existing Load Profiles, and/or creation of new Load Profiles shall be in accordance with Load Profiling Guide Section 2.4, Load Profiling Guide Revision Procedure

(2) Section 9.18, Profile Development Cost Recovery Fee for a Non-ERCOT Sponsored Load Profile Segment, describes the process for compensating the originator of a Load Profile Segment change request by Retail Electric Providers (REPs) wishing to subscribe to the Load Profile Segment.

(3) ERCOT shall give at least 150 days' Notice to all Market Participants prior to market implementation of any change to the Load Profiling Methodology, existing Load Profiles, or when any additional Load Profiles are developed. This Notice shall include a Load Profile change implementation timeline, which specifies dates on which key events during the Load Profile change process will take place. Upon any change in Load Profile Types, TSPs and/or DSPs shall send any revised Load Profile ID assignments required by the change to the registration system within the implementation timeline. After the new Load Profile(s) becomes available, changes to Load Profile Types will be effective on the next meter read date for each ESI ID.

(4) If one or more Load Profiles require changes to reduce excessive UFE, as determined by the appropriate TAC subcommittee, TAC may provide a shorter Notice period and implementation date, than otherwise provided herein, for such required changes to Load Profiles. If the Load Profiling Methodology requires changes to reduce excessive UFE, as determined by the appropriate TAC subcommittee, TAC may provide an expedited Notice period and implementation date.

18.2.9 ERCOT Responsibilities in Support of Load Profiling

(1) ERCOT is responsible for the development and maintenance of Load Profiles used in the ERCOT market. ERCOT shall follow the Load Profiling and Load research rules and procedures as specified in the Public Utility Commission of Texas (PUCT) rules.

18.3 Posting

(1) ERCOT will make available to Market Participants the following information in a timely manner, subject to confidentiality agreements, proprietary arrangements, and Public Utility Commission of Texas (PUCT) rules.

18.3.1 Methodology Information

(1) Upon request, ERCOT will provide a complete description of all supporting Load Profile Models, documentation and data used in preparation of Load Profiles, including:

(a) The historic Load data used to create the Load Profiles;

(b) Average interval accuracy of each Load Profile Model;

(c) Weather information;

(d) Sunrise/sunset information; and

(e) Any other data used for Load Profile development.

18.3.2 Load Profiling Models

(1) ERCOT will make available the Load Profile Models used to produce the forecast and backcast profiles for the Settlement process. The Load Profile Models shall be accessible via the ERCOT website in a downloadable format.

18.3.3 Load Profiles

(1) ERCOT will publish Load Profile data from the Load Profile creation process, in accordance with Section 18.2.6, Daily Profile Creation Process, to the ERCOT website and through the common application program interface (API). Load Profile data will be made available to Market Participants for a period of two years.

(2) ERCOT will post to the ERCOT website by 1000 Central Prevailing Time (CPT) each Business Day, forecasted Load Profiles for the three following days for each Load Profile Type and Weather Zone. Backcast Load Profiles for each Load Profile Type and Weather Zone will be available by 1000 CPT of the second Business Day following the backcast day. No data will be provided that will allow identification of individual Customers.

18.4 Assignment of Load Profile ID

(1) Each Electric Service Identifier (ESI ID) is required to be associated with an appropriate Load Profile ID. Upon request, ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee shall review the Load Profile ID assignment process, make recommendations for enhancements, and evaluate the integration of the validation and assignment processes. This Section details the process of assigning a Load Profile ID to each ESI ID.

18.4.1 Development of Load Profile ID Assignment Table

(1) ERCOT shall develop a cross-reference table of all Load Profile IDs used in the ERCOT market. The table shall clearly state class relationship to Load Profile Type. This information shall be made accessible on the ERCOT website. The cross-reference information shall be compiled and expressed in clear, unambiguous language, and in a manner that will minimize Load Profile ID assignment disputes.

18.4.2 Load Profile ID Assignment

(1) All Load Profile ID assignments shall conform with the valid combinations within the Load Profiling Guide Appendix D, Profile Decision Tree.

(2) Should there be any change in Load Profile ID assignment to any ESI ID, it will be the responsibility of the Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) to submit those changes to ERCOT.

(3) Competitive Retailers (CRs) may dispute a Load Profile ID assignment through the process described in Load Profiling Guide Section 14, Load Profile ID Dispute Procedure.

(4) TSPs and/or DSPs shall change the assignment of a Load Profile ID based on a dispute outcome finding in favor of a CR. If required to change an assignment, TSPs and/or DSPs must correct the assignment in their system and the ERCOT Customer registration system within three Business Days.

18.4.3 Validation of Load Profile Type and Weather Zone Assignments

(1) In this Section validation shall mean performing checks to ensure correct assignment of Load Profile Types and Weather Zones to ESI IDs.

18.4.3.1 Validation Process

(1) Validation of Load Profile Type and Weather Zone assignments, at a minimum, will be performed as follows:

(a) Initial Load Profile ID assignment for opt-in Entities;

(b) When a change is made in the Load Profile Type or Weather Zone assignment;

(c) One time per year for the Business Load Profiles; and

(d) At least one time every three years for the Residential Load Profiles during the Load Profile validation process.

(2) Details of the validation process will be specified in the Load Profiling Guide Section 11, Validation of Load Profile ID.

(3) Any Market Participant may request temporary changes to the process for validating Load Profile IDs to address unusual circumstances. Such change requests shall be recommended by the appropriate TAC subcommittee and approved by TAC. Change requests as a result of an extreme event such as a hurricane or ice storm may be approved directly by TAC. Such requests, if approved by the TAC, shall be in effect only for the requested year.

18.4.3.2 Correction Procedure

(1) TSPs and/or DSPs are responsible for investigating each ESI ID identified by ERCOT or a Market Participant as having a potentially incorrect Load Profile ID assignment. Market Participants may dispute an assignment of a Load Profile ID as described in Load Profiling Guide Section 14, Load Profile ID Dispute Procedure.

18.4.4 Assignment of Weather Zones to Electric Service Identifiers

(1) TSPs and /or DSPs will assign each ESI ID to a Weather Zone, based on service address ZIP code.

(2) ERCOT will post to the ERCOT website a mapping of a Weather Zone to appropriate Customer registration element used in assigning Weather Zones.

18.5 Additional Responsibilities

(1) This Section addresses responsibilities for Load Profiling not specified in other sections of the Protocols.

18.5.1 ERCOT Responsibilities

(1) ERCOT will develop, administer, and maintain Load Profiles in accordance with these Protocols. There may be extenuating circumstances including, but not limited to, prolonged widespread power outages that may necessitate ERCOT's discretion for adjusting non-Interval Data Recorder (IDR) backcasted Load Profiles. If an event requires ERCOT to utilize this discretion, ERCOT shall send a Market Notice within three Business Days of making the adjustments and report its action(s) and reason(s) for doing so to the next meeting of the appropriate Technical Advisory Committee (TAC) subcommittee.

(2) Any disputes related to the accuracy, appropriateness, or adjustment of Load Profiles shall be handled in accordance with Section 9.14, Settlement and Billing Dispute Process.

18.5.2 Market Participant Responsibilities

(1) Market Participants shall use the appropriate TAC subcommittee as a forum for their input in the development and refinement of Load Profiles.

(2) Competitive Retailers (CRs) shall be responsible for reviewing any assignment of Load Profiles to Electric Service Identifiers (ESI IDs) they represent.

18.6 Installation and Use of Interval Data Recorders

18.6.1 Interval Data Recorder Mandatory Installation Requirements

(1) Interval Data Recorders (IDRs) are required and shall be installed and utilized for Settlement of Premises having either:

 (a) A peak Demand greater than 700 kW (or 700 kVA in CenterPoint Energy's service territory); or

 (b) Service provided at transmission voltage (above 60 kV).

(2) All non-metered Loads such as street lighting, regardless of the aggregation level, shall not be required to install IDRs under the IDR Mandatory Installation Requirements. These Loads shall be settled using Load Profiles.

(3) Municipally Owned Utilities (MOUs) and Electric Cooperatives (ECs) that opt-in to Customer Choice must install IDRs at all Premises subject to the IDR Mandatory Installation Requirements for metering prior to the effective date of their participation in the testing and integration requirements of ERCOT systems for Customer Choice.

18.7 Transition of Interval Data Recorder Meter to AMS Profile Type

(1) At a Transmission and/or Distribution Service Provider's (TDSP's) discretion, or upon a Customer's request and TDSP's approval, a TDSP shall:

 (a) Utilize a provisioned Advanced Meter or similarly functional meter for Customer's Premise;

 (b) Assign the appropriate Load Profile, other than one with a BUSIDRRQ Profile Type Code, to Premise's Electric Service Identifier (ESI ID);

 (c) Submit Settlement Quality Meter Data, which will be used for Settlement, using the ERCOT specified file format for the interval data only in accordance with Retail Market Guide Section 7.15, Advanced Meter Interval Data File Format and Submission;

 (d) If the ESI ID will be transitioning to an Advanced Metering System (AMS) Profile Type other than BUSLRG or BUSLRGDG, submit a MarkeTrak issue to notify ERCOT; and

 (e) Submit the appropriate Texas Standard Electronic Transaction (TX SET) transaction notifying the Competitive Retailer (CR) of the Load Profile change.

ERCOT Nodal Protocols

Section 19: Texas Standard Electronic Transaction

May 1, 2021

19 TEXAS STANDARD ELECTRONIC TRANSACTION

(1) This Section of the Protocols contains an overview of the purpose and scope of the Texas Standard Electronic Transaction (TX SET), and a series of definitions identifying the use of each transaction. It also refers to the full Texas SET Implementation Guides, which are posted on the ERCOT website.

19.1 Overview

(1) Texas Standard Electronic Transactions (TX SETs) provide the mechanism that enables and facilitates the retail business processes in the deregulated Texas electric market. The Texas SET Implementation Guides and Texas SET Change Control process documents shall be posted on the ERCOT website. The Texas SET Implementation Guides shall serve as the standard for the applicable TX SETs among all Market Participants and ERCOT.

(2) This Section shall cover:

(a) Transactions between Transmission and/or Distribution Service Providers (TDSPs) (refers to all TDSPs unless otherwise specified), Competitive Retailers (CRs) and ERCOT;

(b) Technical Advisory Committee (TAC) subcommittee and ERCOT responsibilities; and

(c) Texas SET Change Control process.

19.2 Methodology

(1) In developing and maintaining the implementation guides, the appropriate Technical Advisory Committee (TAC) subcommittee shall:

(a) Develop standardized transactions, which support documented ERCOT market business requirements across all Market Participants and ERCOT;

(b) Develop Electronic Data Interchange (EDI) transactions using American National Standards Institute Accredited Standards Committee X12 (ANSI ASC X12) standards;

(c) Develop Extensible Markup Language (XML) transactions as needed;

(d) Develop other spreadsheets, templates, comma separated value (CSV) files, etc. as needed;

(e) Follow 'Best Practices' as identified in the overall technology market place related to development of Texas Standard Electronic Transactions (TX SETs); and

(f) Develop processes and procedures for the management of changes to TX SETs and the release of new versions of TX SETs.

19.3 Texas Standard Electronic Transaction Definitions

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.

(4) **Planned or Unplanned Outage Response (650_05)**

This transaction set is no longer valid as of Texas 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. 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.

(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, 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 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 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 CR, is used to cancel pending transaction involved in an acquisition 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 acquisition transition.

(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 CR, is used in response to an acquisition 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.

(e) From ERCOT to the MOU/EC TDSP, is used for notification of CSA deletion.

(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.

(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 request.

(b) From ERCOT to the TDSP, is notification of the Customer's move out 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. 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.

(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 (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.

19.4 Texas Standard Electronic Transaction Change Control Process

(1) The appropriate Technical Advisory Committee (TAC) subcommittee shall make modifications and additions to the Texas Standard Electronic Transactions (TX SETs) in accordance with this Section. TX SETs will be expanded and modified to accommodate

retail market operations or regulatory requirements on an ongoing basis. Each Market Participant will rely on established, documented, and tested transactions. The Texas SET Change Control process provides the mechanism by which changes to the Texas SET Implementation Guides may be discussed, reviewed, accepted, and implemented.

19.4.1 Technical Advisory Committee Subcommittee Responsibilities

(1) The appropriate TAC subcommittee will continue to:

(a) Review and approve Texas SET Change Controls;

(b) Classify a Texas SET Change Control request as urgent when the change meets the criteria in Section 19.4.5, Urgent Change Request;

(c) Review and approve Texas SET Implementation Guides; and

(d) Coordinate timing for changes in any of the TX SETs.

19.4.2 ERCOT Responsibilities

(1) ERCOT will facilitate the activities listed in Section 19.4, Texas Standard Electronic Transaction Change Control Process, by overseeing the Texas SET Change Control activities of the TX SETs.

(2) ERCOT, in conjunction with the appropriate TAC subcommittee, will maintain, publish, and post the Texas SET Implementation Guides and the Texas SET Change Controls requesting modifications and enhancements, to the ERCOT website.

(a) The Texas SET Change Controls shall be published by ERCOT within seven Retail Business Days of approval by the appropriate TAC subcommittee.

(b) The approved Texas SET Implementation Guides shall be published by ERCOT at a predetermined time as set by the appropriate TAC subcommittee.

19.4.3 Texas SET Change Control Dispute Process

(1) A Market Participant may register a dispute with ERCOT by completing the designated form provided on the ERCOT website within seven days after the date of the appropriate TAC subcommittee decision. ERCOT shall reject disputes made after that time. The dispute shall be submitted to txsetchangecontrol@ercot.com. ERCOT shall post disputes with the applicable change control within three Business Days of receiving the dispute.

(2) Disputes shall be heard at the next regularly scheduled TAC meeting. However, if the dispute is posted within seven days of the TAC meeting the dispute will not be heard until the subsequent TAC meeting. A dispute of a Texas SET Change Control to TAC

suspends any further decisions on the Texas SET Change Control until the dispute has been decided by TAC.

19.4.4 Submission of Proposed Changes

(1) An Entity proposing a change shall notify ERCOT by submitting the designated form provided on the ERCOT website.

(2) Texas SET Change Controls will be processed in accordance with the Texas Standard Electronic Transaction Implementation Guides Change Control Process located on the ERCOT website.

(3) Texas SET Change Controls will proceed on a normal timeline unless classified as urgent as described in Section 19.4.5, Urgent Change Request.

19.4.5 Urgent Change Request

(1) A Texas SET Change Control may be classified as urgent by the appropriate TAC subcommittee and will accommodate:

(a) An approved regulatory requirement; and /or

(b) Necessary corrective action to retail market processes.

(2) Urgent Texas SET Change Controls shall be implemented as prescribed by the approving TAC subcommittee.

19.5 Texas Standard Electronic Transactions Acceptable Character Set

19.5.1 Alphanumeric Field(s)

(1) For use on an alphanumeric field, Texas Standard Electronic Transaction (TX SET) recognizes all characters within the basic character set. Further clarification and additional character set validations are available within each Texas SET Implementation Guide that is located on the ERCOT website.

19.6 Texas Standard Electronic Transaction Envelope Standards

19.6.1 ERCOT Validation

(1) ERCOT acts as the certificate authority and generates a digital certificate on behalf of each Market Participant. The Market Participant must be identified uniquely within the ERCOT System.

19.7 Advanced Meter Interval Data Format and Submission

(1) Transmission and/or Distribution Service Providers (TDSPs) will provide 15-minute interval data to ERCOT from provisioned Advanced Meters and Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ Interval Data Recorders (IDRs) using an ERCOT specified file format submitted via North American Energy Standards Board (NAESB) on at least a monthly basis.

19.8 Retail Market Testing

(1) The Texas Standard Electronic Transaction (TX SET) Working Group works with the ERCOT flight administrator to develop and maintain a test plan and related testing standards for all retail transactional changes within the ERCOT market. Testing of these changes is scheduled to allow ERCOT and all Market Participants adequate time to modify their systems and participate in the testing process. Testing processes, procedures, schedules and success criteria are defined in the Texas Market Test Plan (TMTP) Guide and on the ERCOT website. The ERCOT flight administrator is the final authority on all levels of retail business process qualification among trading partners.

(2) ERCOT may enlist the services of an Independent Third Party Testing Administrator (ITPTA) for this testing process.

ERCOT Nodal Protocols

Section 20: Alternative Dispute Resolution Procedure

April 1, 2021

20 ALTERNATIVE DISPUTE RESOLUTION PROCEDURE

20.1 Applicability

(1) Except as otherwise provided in Section 20, Alternative Dispute Resolution Procedure, this Alternative Dispute Resolution (ADR) procedure applies to any claim by a Market Participant that ERCOT has violated or misinterpreted any law, including any statute, rule, Protocol, Other Binding Document, or Agreement, where such violation or misinterpretation results in actual harm, or could result in imminent harm, to the Market Participant. A Market Participant that disputes an interpretation of the ERCOT Protocols, an Other Binding Document, or an Agreement made by ERCOT through the Protocol interpretation request process described in subsection (i) of P.U.C. SUBST. R. 25.503, Oversight of Wholesale Market Participants, is not required to follow the ADR procedure prior to seeking relief from the Public Utility Commission of Texas (PUCT) or other Governmental Authority.

(2) Only a Counter-Party may request ADR to seek correction of Settlement data and resettlement, except that:

(a) A Market Participant that is not a Counter-Party may submit an ADR request seeking correction of Settlement data and resettlement on behalf of an affected Counter-Party upon providing ERCOT written documentation executed by the Authorized Representative of the Counter-Party designating the Market Participant as the Counter-Party's agent for purposes of submitting the ADR request; and

(b) A Load Serving Entity (LSE), with its Counter-Party, or a Transmission and/or Distribution Service Provider (TDSP) may submit an ADR request for correction of Electric Service Identifier (ESI ID) service history, usage information, and/or resettlement, as set forth in these Protocols and the Retail Market Guide.

(3) Nothing in this ADR procedure is intended to limit or restrict the right of a Market Participant to file a petition seeking direct relief from the PUCT or another Governmental Authority without first exhausting this ADR procedure where actual or threatened action by ERCOT or a Market Participant could cause irreparable harm and where such harm cannot be addressed within the time permitted under the ADR process.

(4) Except for the provisions of this Section 20.1, the ADR procedure may be modified by mutual agreement of the parties.

(5) Parties shall exercise good faith efforts to timely resolve disputes under Section 20.

(6) Nothing contained in Section 20 is intended to supersede any dispute resolution process mandated by applicable law or tariff. Furthermore, this ADR procedure does not apply to any dispute concerning an agreement between Market Participants or the terms of any tariff. To the extent any dispute not governed by Section 20 involves the interpretation of the ERCOT Protocols, an Other Binding Document, or an Agreement, that dispute may

be submitted to ERCOT through the Protocol interpretation request process described in subsection (i) of P.U.C. SUBST. R. 25.503.

20.2 Deadline for Initiating ADR Proceeding

(1) The following deadlines shall apply for the initiation of an Alternative Dispute Resolution (ADR) proceeding:

(a) For any ADR proceeding invoked in connection with a Settlement and billing dispute submitted pursuant to Section 9.14, Settlement and Billing Disputes, the Market Participant must submit a complete written request for ADR no later than 45 days after the resolution date on which ERCOT denied the Market Participant's Settlement and billing dispute.

(b) For any ADR proceeding invoked in connection with the rejection or rescission (or a portion thereof) of a verifiable cost, or rejection of a verifiable cost appeal, the Market Participant must submit a complete written request for ADR no later than 45 days after either:

(i) Rejection or rescission (or a portion thereof) of a verifiable cost; or

(ii) Notice from ERCOT that the appeal, in whole or in part, has been rejected.

(b) For any ADR proceeding invoked in connection with a disagreement arising from a Data Extract Variance process, the Market Participant must submit a complete written request for ADR no later than 45 days after issuance of the True-Up Statement for the applicable Operating Day.

(c) For any ADR proceeding invoked in connection with any other matter, the Market Participant must submit a complete written request for ADR no later than six months after the date on which information giving rise to the ADR request became available to the Market Participant.

(2) If the Market Participant requesting ADR does not submit a complete written request for ADR (as set forth in Section 20.4, Initiation of ADR Proceedings) within the time required by paragraph (1) above, the Market Participant waives any claim regarding the dispute.

20.3 Exhaustion of Other Dispute Resolution Procedures

(1) When a section of these Protocols, an Other Binding Document, or an Agreement sets forth a dispute resolution procedure, a Market Participant shall exhaust that procedure prior to initiating an Alternative Dispute Resolution (ADR) proceeding, including but not limited to the following:

(a) If a Market Participant seeks resolution of a variance subject to the Data Extract Variance Process, the Market Participant must comply with that process prior to initiating an ADR proceeding, or the claim is waived.

(b) If a Counter-Party seeks correction of Settlement data and resettlement, except for resolution of a variance subject to the Data Extract Variance Process as described in paragraph (a) above, the Counter-Party must comply with the process set forth in Section 9.14, Settlement and Billing Dispute Process, prior to initiating an ADR proceeding, or the claim is waived.

20.4 Initiation of ADR Proceedings

(1) To initiate an Alternative Dispute Resolution (ADR) proceeding, a Market Participant shall complete and submit to the ERCOT Legal Department the designated form provided on the ERCOT website in the manner required by the form.

(a) All written requests shall include the following information:

(i) The name of the disputing Market Participant;

(ii) A description of the relief sought;

(iii) A detailed description of the grounds for the relief and the basis of each claim that must, at a minimum, identify which statute(s), rule(s), Protocol Section(s), Other Binding Document(s), Agreement(s) or other law(s) are alleged to have been violated;

(iv) A list of all other parties that would be affected by the dispute; and

(v) Designation of a senior dispute representative.

(b) For ADR proceedings for which the Market Participant seeks a monetary resolution, the Market Participant shall also include the following information:

(i) Operating Day(s) involved in the dispute;

(ii) Settlement dispute number (if applicable); and

(iii) Amount of compensation requested.

(2) The date on which ERCOT receives the completed ADR written request shall be the ADR initiation date.

20.5 Alternative Dispute Resolution Process

(1) No later than seven days after the Alternative Dispute Resolution (ADR) initiation date, ERCOT shall determine, and provide Notice to, all parties directly involved in the

dispute. Such Notice shall include the ADR file number and the designation of the ERCOT senior dispute representative.

(2) For ADR proceedings that involve more than one Market Participant, each Market Participant other than the Market Participant that submitted the ADR request shall provide the name and contact information of a senior dispute representative no later than seven days after receipt of Notice from ERCOT pursuant to paragraph (1) above. If a Market Participant does not provide this information within the time required, the Market Participant waives its right to participate in the ADR proceeding.

(3) Any dispute subject to ADR as described in this Section shall be referred to a senior dispute representative of each of the parties to the dispute. The senior dispute representative shall be an individual with authority to resolve the dispute (through delegation or otherwise). A disputing party may change its senior dispute representative upon reasonable written notice to all parties though such redesignation shall not extend any of the ADR timelines.

(4) The parties to the dispute shall arrange a mutually convenient time and place for a meeting, with the initial ADR meeting taking place no later than 75 days after the ADR initiation date unless all parties agree to an extension of time. If the party that submitted the request for ADR fails to make reasonable efforts to schedule and attend the initial ADR meeting within the time required (including any agreed-upon extension of time), ERCOT may, in its sole discretion, deny the dispute.

(5) After the initial ADR meeting, ERCOT may approve or deny the dispute in whole or in part by issuing the disposition Market Notice described in paragraph (1) of Section 20.9, Resolution of Alternative Dispute Resolution Proceedings and Notification to Market Participants. ERCOT must issue the Market Notice disposing of the ADR request no later than 30 days after the initial ADR meeting unless all parties agree in writing to an extension of time.

(6) If the senior dispute representatives cannot resolve the dispute by mutual agreement within 45 days after the initial senior dispute resolution meeting (unless all parties agree in writing to an extension of time), then, upon the agreement of all parties to the ADR, the dispute may be referred to mediation pursuant to Section 20.6, Mediation Procedures.

(7) The parties to the dispute may elect to waive ADR by written agreement, which will also complete the ADR proceeding.

(8) The following table summarizes the ADR process timelines:

Deadline to submit ADR Request to ERCOT	**ERCOT Notice of Receipt**	**Other Market Participant Contact Info to ERCOT[1]**		**ERCOT/ Market Participant Initial ADR meeting**	**ERCOT/ Market Participant resolution of ADR**
≤ 45 days of denial	**≤ 7 days** after ADR initiation date	**≤ 7 days** after receipt of		**≤ 75 days** after ADR	**≤ 30 days** after initial ADR

(Settlement and billing dispute denied by ERCOT) **≤ 45 days** of True-Up (Data Extract Variance dispute not resolved by True-Up) **≤ 6 months** from date on which information giving rise to ADR request became available (any other dispute)		ERCOT Notice of receipt		initiation date[2]	meeting[2]

Notes:

1. If required pursuant to paragraph (2) above.
2. Unless all parties agree to an extension of time.

20.6 Mediation Procedures

(1) The parties shall agree on a mediator who has no past or present official, financial, or personal conflict of interest with respect to the issues or parties in dispute, unless the interest is fully disclosed in writing to all participants in the dispute and all such participants waive in writing any objection to the conflict of interest. If the parties are unable to agree on a mediator within ten days of the agreement to mediate, then the Commercial Mediation Rules of the American Arbitration Association (AAA) will be used to select the mediator.

(2) The mediator and senior dispute representatives of the parties shall commence mediation of the dispute within ten days after the mediator's date of appointment. Communications regarding mediation shall be confidential and shall not be referred to or disclosed in any subsequent proceeding. The mediator shall aid the parties in reaching a mutually acceptable resolution of the dispute. If agreement regarding the Alternative Dispute Resolution (ADR) cannot be reached, any of the parties may apply for relief to the Public Utility Commission of Texas (PUCT), or any other Governmental Authority.

20.7 Alternative Dispute Resolution Costs

(1) Each party shall be responsible for its own costs incurred during an Alternative Dispute Resolution (ADR) proceeding.

20.8 Requests for Documents and Data

(1) If, as part of the Alternative Dispute Resolution (ADR) proceeding, a party requests documents or data from another party to the ADR proceeding, the responding party must provide one of the following within 15 days of the request:

(a) The requested documents or data;

(b) An explanation of why the documents or data should not be produced (*e.g.* relevance); or

(c) An explanation of why the information cannot be provided on that date and a reasonable date on which the documents or data will be produced.

(2) All information provided pursuant to this subsection shall be provided by mail, email, or other mutually agreed-upon method.

20.9 Resolution of Alternative Dispute Resolution Proceedings and Notification to Market Participants

(1) If ERCOT has determined the appropriate disposition of an Alternative Dispute Resolution (ADR) proceeding, ERCOT shall issue a Market Notice providing a brief description of the relevant facts, a list of the parties involved in the dispute, the disposition of the proceeding and the reasoning supporting the resolution. No later than seven days prior to issuing a Market Notice pursuant to this paragraph (1), ERCOT shall provide a copy of the proposed Market Notice, including the proposed issuance date, to the party that submitted the request for ADR, who may comment on the proposed Market Notice.

(2) In addition to the Market Notice described in paragraph (1) above, if an ADR claim is approved in whole or in part, ERCOT shall issue a Market Notice describing the total resettlement amount and the manner in which the resulting overpayments or underpayments will be allocated to the appropriate Settlement Statement recipients and Invoice Recipients, including the specific Settlement Statements and Invoices that will be affected. The Market Notice shall include the information required by Section 9.2.6, Notice of Resettlement for the DAM, or Section 9.5.7, Notice of Resettlement for the Real-Time Market, as applicable.

(3) If, in connection with the disposition of an ADR proceeding, ERCOT determines that it is appropriate to correct Day-Ahead Market Clearing Prices for Capacity (MCPCs), Day-Ahead hourly Locational Marginal Prices (LMPs), Day-Ahead Settlement Point Prices (DASPPs), Real-Time Settlement Point Prices, Real-Time Settlement Point LMPs, Real-Time Electrical Bus LMPs, Real-Time prices for energy metered, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reliability Deployment Adders, Real-Time On-Line Reliability Deployment Prices, and/or constraint Shadow Prices, approval of the ERCOT Board

pursuant to paragraph (6) of Section 4.5.3, Communicating DAM Results, or paragraph (7) of Section 6.3, Adjustment Period and Real-Time Operations Timeline, as applicable, is not required.

(4) Upon issuance of the Market Notice described in paragraph (1) above, the ADR process shall be deemed complete, and any Market Participant that is adversely affected may appeal ERCOT's decision to the Public Utility Commission of Texas (PUCT) pursuant to P.U.C. PROC. R. 22.251, Review of Electric Reliability Council of Texas (ERCOT) Conduct.

20.10 Settlement of Approved Alternative Dispute Resolution Claims

20.10.1 Adjustments Based on Alternative Dispute Resolution

(1) If resettlement is practicable to address an adjustment required by the resolution of an Alternative Dispute Resolution (ADR) proceeding, ERCOT shall issue a Resettlement Statement for the affected Operating Day(s) and shall adjust applicable timelines accordingly.

(2) If a resettlement is not practicable to address an adjustment required by an ADR resolution, ERCOT shall make the adjustments through a separate ADR Invoice that is produced outside of normal Settlement Invoices. The appropriate payments and charges, along with settlement quality information, shall be supplied to all impacted Market Participants.

(3) Any amount greater than $5,000,000, as approved through the ADR proceeding, shall be divided so that no one Invoice has more than $5,000,000 in ADR adjustments and such Invoices shall be issued at least 14 days apart from each other. Payments shall be due on the date specified on the Invoice. Any short payment shall be handled pursuant to Section 9.19, Partial Payments by Invoice Recipients.

20.10.2 Charges for Approved ADR Claim

(1) The charges assigned to Market Participants to pay for an approved ADR claim shall be settled on the same Resettlement Statement or ADR Invoice as set forth in Section 20.10.1, Adjustments Based on Alternative Dispute Resolution. ERCOT shall assign the costs for the approved ADR claim according to the appropriate allocation for the market service in dispute as outlined in the applicable Protocol sections.

ERCOT Nodal Protocols

Section 21: Revision Request Process

January 1, 2021

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21 REVISION REQUEST PROCESS

21.1 Introduction

(1) A request to make additions, edits, deletions, revisions, or clarifications to these Protocols, including any attachments and exhibits to these Protocols, is called a Nodal Protocol Revision Request (NPRR). Except as specifically provided otherwise in the following sentence or in other sections of these Protocols, Sections 21.2, Submission of a Nodal Protocol Revision Request or System Change Request, through 21.8, Review of Guide Changes, apply to all NPRRs. ERCOT Members, Market Participants, Public Utility Commission of Texas (PUCT) Staff, the Reliability Monitor, the Independent Market Monitor (IMM), the North American Electric Reliability Corporation (NERC) Regional Entity, ERCOT, and any other Entities are required to utilize the process described herein prior to requesting, through the PUCT or other Governmental Authority, that ERCOT make a change to these Protocols, except for good cause shown to the PUCT or other Governmental Authority.

(2) A request that ERCOT change its computer systems that does not require a revision to the Protocols is called a System Change Request (SCR). Except as specifically provided in other sections of these Protocols, Sections 21.2 through 21.7, Review of Project Prioritization and Annual Budget Process, apply to all SCRs.

(3) The “next regularly scheduled meeting” of the Protocol Revision Subcommittee (PRS), the Technical Advisory Committee (TAC), an Assigned TAC Subcommittee (as defined below), or the ERCOT Board shall mean the next regularly scheduled meeting for which required notice can be timely given regarding the item(s) to be addressed, as specified in the appropriate ERCOT Board or committee procedures.

(4) ERCOT may make non-substantive corrections at any time during the processing of a particular NPRR. Under certain circumstances, however, the Nodal Protocols can also be revised by ERCOT rather than using the NPRR process outlined in Section 21.4, Nodal Protocol Revision and System Change Procedure.

  (a) This type of revision is referred to as an “Administrative NPRR” or “Administrative Changes” and shall consist of non-substantive corrections, such as typos (excluding grammatical changes), internal references (including table of contents), improper use of acronyms, and references to ERCOT Protocols, PUCT Substantive Rules, the Public Utility Regulatory Act (PURA), North American Electric Reliability Corporation (NERC) regulations, Federal Energy Regulatory Commission (FERC) rules, etc. Additionally, updates to Section 23, Forms, may also be processed as Administrative NPRRs.

  (b) ERCOT shall post such Administrative NPRRs to the ERCOT website and distribute the NPRR to PRS at least ten Business Days before implementation. If no Entity submits comments to the Administrative NPRR in accordance with paragraph (1) of Section 21.4.4, Protocol Revision Subcommittee Review and Action, ERCOT shall implement it according to paragraph (4) of Section 21.6, Nodal Protocol Revision Implementation. If any ERCOT Member, Market Participant, PUCT Staff, Reliability Monitor Staff, NERC Regional Entity Staff, the IMM, or ERCOT submits comments to the Administrative NPRR, then it shall be processed in accordance with the NPRR process outlined in Section 21.4.

21.2 Submission of a Nodal Protocol Revision Request or System Change Request

(1) The following Entities may submit a Nodal Protocol Revision Request (NPRR) or System Change Request (SCR) ("Revision Request"):

(a) Any Market Participant;

(b) Any ERCOT Member;

(c) Public Utility Commission of Texas (PUCT) Staff;

(d) The Reliability Monitor;

(e) The North American Electric Reliability Corporation (NERC) Regional Entity;

(f) The Independent Market Monitor (IMM);

(g) ERCOT; and

(h) Any other Entity that meets the following qualifications:

(i) Resides (or represents residents) in Texas or operates in the Texas electricity market; and

(ii) Demonstrates that Entity (or those it represents) is affected by the Customer Registration or Renewable Energy Credit (REC) Trading Program sections of these Protocols.

21.3 Protocol Revision Subcommittee

(1) The Protocol Revision Subcommittee (PRS) shall review and recommend action on formally submitted Nodal Protocol Revision Requests (NPRRs) and System Change Requests (SCRs) ("Revision Requests") provided that:

(a) PRS meetings are open to ERCOT, ERCOT Members, Market Participants, the Reliability Monitor, the North American Electric Reliability Corporation (NERC) Regional Entity, the Independent Market Monitor (IMM), and the Public Utility Commission of Texas (PUCT) Staff;

(b) Each Market Segment is allowed to participate; and

(c) Each Market Segment has equal voting power.

(2) Where additional expertise is needed, the PRS may refer a Revision Request to working groups or task forces that it creates or to existing Technical Advisory Committee (TAC) subcommittees, working groups or task forces for review and comment on the Revision Request. Suggested modifications—or alternative modifications if a consensus recommendation is not achieved by a non-voting working group or task force—to the Revision Request should be submitted by the chair or the chair's designee on behalf of the subcommittee, working group or task force as comments on the Revision Request for consideration by PRS. However, the PRS shall retain ultimate responsibility for the processing of all Revision Requests.

(3) ERCOT shall consult with the PRS chair to coordinate and establish the meeting schedule for the PRS. The PRS shall meet at least once per month and shall ensure that reasonable advance notice of each meeting, including the meeting agenda, is posted on the ERCOT website.

21.4 Nodal Protocol Revision and System Change Procedure

21.4.1 Review and Posting of Nodal Protocol Revision Requests

(1) Nodal Protocol Revision Requests (NPRRs) shall be submitted electronically to ERCOT by completing the designated form provided on the ERCOT website. Excluding ERCOT-sponsored NPRRs, ERCOT shall provide an electronic return receipt response to the submitter upon receipt of the NPRR.

(2) The NPRR shall include the following information:

(a) Description of requested revision and reason for suggested change;

(b) Impacts and benefits of the suggested change on ERCOT market structure, ERCOT operations, and Market Participants, to the extent that the submitter may know this information;

(c) List of affected Nodal Protocol Sections and subsections;

(d) General administrative information (organization, contact name, etc.); and

(e) Suggested language for requested revision.

(3) ERCOT shall evaluate the NPRR for completeness and shall notify the submitter, within five Business Days of receipt, if the NPRR is incomplete, including the reasons for such status. ERCOT may provide information to the submitter that will correct the NPRR and render it complete. An incomplete NPRR shall not receive further consideration until it is completed. In order to pursue the NPRR, a submitter must submit a completed version of the NPRR.

(4) If a submitted NPRR is complete or upon completion of an NPRR, ERCOT shall post the NPRR on the ERCOT website and distribute to the Protocol Revision Subcommittee (PRS) within three Business Days.

(5) For any ERCOT-sponsored NPRR, ERCOT shall also post an initial Impact Analysis on the ERCOT website, and distribute it to PRS. The initial Impact Analysis will provide PRS with guidance as to potential ERCOT computer systems, operations, or business functions that could be affected by the submitted NPRR.

21.4.2 Review and Posting of System Change Requests

(1) System Change Requests (SCRs) shall be submitted electronically to ERCOT by completing the designated form provided on the ERCOT website. Excluding ERCOT-sponsored SCRs, ERCOT shall provide an electronic return receipt response to the submitter upon receipt of the SCR.

(2) The SCR shall include the following information:

(a) Description of desired additional system functionality or the additional information desired and reason for suggested change;

(b) Impacts and benefits of the suggested change to ERCOT market structure, ERCOT operations and Market Participants, to the extent that submitter may know this information;

(c) General administrative information (organization, contact name, etc.); and

(d) Summary of requested changes to ERCOT systems.

(3) ERCOT shall evaluate the SCR to determine whether the request should be submitted as an NPRR. If ERCOT determines that the SCR should be submitted as an NPRR, ERCOT will notify the submitter within five Business Days of receipt, and the submitter shall withdraw its SCR and may submit an NPRR in its place. If ERCOT deems it necessary for further review beyond the five Business Days, ERCOT shall notify the submitter.

(4) ERCOT shall evaluate the SCR for completeness and shall notify the submitter, within five Business Days, if the SCR is incomplete, including the reasons for such status. ERCOT may provide information to the submitter that will correct the SCR and render it complete. An incomplete SCR shall not receive further consideration until it is completed. In order to pursue the SCR requested, the submitting Entity must submit a completed version of the SCR.

(5) If a submitted SCR is complete or upon completion of an SCR, ERCOT shall post the SCR on the ERCOT website and distribute to the PRS within three Business Days.

(6) For any ERCOT-sponsored SCR, ERCOT shall also post an initial Impact Analysis on the ERCOT website, and distribute it to PRS. The initial Impact Analysis will provide

PRS with guidance as to potential ERCOT computer systems, operations, or business functions that could be affected by the submitted SCR.

21.4.3 Withdrawal of a Nodal Protocol Revision Request or System Change Request

(1) A submitter may withdraw or request to withdraw an NPRR or SCR ("Revision Request") by submitting a completed Request for Withdrawal form provided on the ERCOT website. ERCOT shall post the submitter's Request for Withdrawal on the ERCOT website within three Business Days of submittal.

(2) The submitter of a Revision Request may withdraw the Revision Request at any time before PRS recommends approval of the Revision Request. If PRS has recommended approval of the Revision Request, the request for withdrawal must be approved by the Technical Advisory Committee (TAC) if the Revision Request has not yet been recommended for approval by TAC. If TAC has recommended approval of the Revision Request, the request for withdrawal must be approved by the ERCOT Board if the Revision Request has not yet been approved by the ERCOT Board. Once approved by the ERCOT Board, a Revision Request cannot be withdrawn.

21.4.4 Protocol Revision Subcommittee Review and Action

(1) Any ERCOT Member, Market Participant, the Public Utility Commission of Texas (PUCT) Staff, the Reliability Monitor, the North American Electric Reliability Corporation (NERC) Regional Entity, the Independent Market Monitor (IMM), or ERCOT may comment on a Revision Request.

(2) To receive consideration, comments must be delivered electronically to ERCOT in the designated format provided on the ERCOT website within 14 days from the posting date of the Revision Request. Comments submitted after the 14 day comment period may be considered at the discretion of PRS after these comments have been posted. Comments submitted in accordance with the instructions on the ERCOT website—regardless of date of submission—shall be posted to the ERCOT website and distributed to the PRS within three Business Days of submittal.

(3) The PRS shall consider the Revision Request at its next regularly scheduled meeting after the end of the 14 day comment period. At such meeting, the PRS may take action on the Revision Request. The quorum and voting requirements for PRS action are set forth in the Technical Advisory Committee Procedures. In considering action on a Revision Request, PRS may:

(a) Recommend approval of the Revision Request as submitted or as modified;

(b) Reject the Revision Request;

(c) Defer decision on the Revision Request; or

(d) Refer the Revision Request to another TAC subcommittee, working group, or task force as provided in Section 21.3, Protocol Revision Subcommittee.

(4) If a motion is made to recommend approval of a Revision Request and that motion fails, the Revision Request shall be deemed rejected by PRS unless at the same meeting PRS later votes to recommend approval of, defer, or refer the Revision Request. The rejected Revision Request shall be subject to appeal pursuant to Section 21.4.11.1, Appeal of Protocol Revision Subcommittee Action.

(5) Within three Business Days after PRS takes action, ERCOT shall post a PRS Report reflecting the PRS action on the ERCOT website. The PRS Report shall contain the following items:

(a) Identification of submitter of the Revision Request;

(b) Protocol language or summary of requested changes to ERCOT systems, recommended by the PRS, if applicable;

(c) Identification of authorship of comments;

(d) Proposed effective date(s) of the Revision Request;

(e) Priority and rank for any Revision Requests requiring an ERCOT project for implementation; and

(f) PRS action.

(6) The PRS chair shall notify TAC of Revision Requests rejected by PRS.

21.4.5 Comments to the Protocol Revision Subcommittee Report

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the NERC Regional Entity, the IMM, or ERCOT may comment on the PRS Report. Comments submitted in accordance with the instructions on the ERCOT website—regardless of date of submission—shall be posted on the ERCOT website and distributed to the committee(s) (i.e., PRS and/or TAC) considering the Revision Request within three Business Days of submittal.

(2) The comments on the PRS Report will be considered at the next regularly scheduled PRS or TAC meeting where the Revision Request is being considered.

21.4.6 Revision Request Impact Analysis

(1) If PRS recommends approval of a Revision Request, ERCOT shall prepare an Impact Analysis based on the proposed language or proposed system changes in the PRS Report. If ERCOT has already prepared an Impact Analysis, ERCOT shall update the existing

Impact Analysis, if necessary, to accommodate the language or system changes recommended for approval in the PRS Report.

(2) The Impact Analysis shall assess the impact of the proposed Revision Request on ERCOT staffing, computer systems, operations, or business functions and shall contain the following information:

(a) An estimate of any cost and budgetary impacts to ERCOT for both implementation and on-going operations;

(b) The estimated amount of time required to implement the Revision Request;

(c) The identification of alternatives to the Revision Request that may result in more efficient implementation; and

(d) The identification of any manual workarounds that may be used as an interim solution and estimated costs of the workaround.

(3) Unless a longer review period is warranted due to the complexity of the proposed PRS Report, ERCOT shall post an Impact Analysis on the ERCOT website, for a Revision Request for which PRS has recommended approval of, prior to the next regularly scheduled PRS meeting, and distribute to PRS. If a longer review period is required by ERCOT to complete an Impact Analysis, ERCOT shall submit comments with a schedule for completion of the Impact Analysis.

21.4.7 Protocol Revision Subcommittee Review of Impact Analysis

(1) After ERCOT posts the results of the Impact Analysis, PRS shall review the Impact Analysis at its next regularly scheduled meeting. PRS may revise its PRS Report after considering the information included in the Impact Analysis or additional comments received on the PRS Report.

(2) Within three Business Days of PRS consideration of the Impact Analysis and PRS Report, ERCOT shall post the PRS Report on the ERCOT website. If PRS revises the PRS Report, ERCOT shall update the Impact Analysis, if necessary, post the updated Impact Analysis on the ERCOT website, and distribute it to the committee(s) (i.e., PRS and/or TAC) considering the Impact Analysis. If a longer review period is required for ERCOT to update the Impact Analysis, ERCOT shall submit comments with a schedule for completion of the Impact Analysis.

(3) If the Revision Request requires an ERCOT project for implementation, at the same meeting, PRS shall assign a recommended priority and rank for the associated project.

21.4.8 Technical Advisory Committee Vote

(1) TAC shall consider any Revision Requests that PRS has submitted to TAC for consideration for which both a PRS Report and an Impact Analysis (as updated if modified by PRS under Section 21.4.7, Protocol Revision Subcommittee Review of Impact Analysis) have been posted on the ERCOT website. The following information must be included for each Revision Request considered by TAC:

(a) The PRS Report and Impact Analysis;

(b) The recommended PRS priority and rank, if an ERCOT project is required; and

(c) Any comments timely received in response to the PRS Report.

(2) The quorum and voting requirements for TAC action are set forth in the Technical Advisory Committee Procedures. In considering action on a PRS Report, TAC shall:

(a) Recommend approval of the Revision Request as recommended in the PRS Report or as modified by TAC, including modification of the recommended priority and rank if the Revision Request requires a project;

(b) Reject the Revision Request;

(c) Defer decision on the Revision Request;

(d) Remand the Revision Request to PRS with instructions; or

(e) Refer the Revision Request to another TAC subcommittee or a TAC working group or task force with instructions.

(3) If a motion is made to recommend approval of a Revision Request and that motion fails, the Revision Request shall be deemed rejected by TAC unless at the same meeting TAC later votes to recommend approval of, defer, remand, or refer the Revision Request. If a motion to recommend approval of a Revision Request fails via email vote according to the Technical Advisory Committee Procedures, the Revision Request shall be deemed rejected by TAC unless at the next regularly scheduled TAC meeting or in a subsequent email vote prior to such meeting, TAC votes to recommend approval of, defer, remand, or refer the Revision Request. The rejected Revision Request shall be subject to appeal pursuant to Section 21.4.11.2, Appeal of Technical Advisory Committee Action.

(4) Within three Business Days after TAC takes action on the Revision Request, ERCOT shall post a TAC Report reflecting the TAC action on the ERCOT website. The TAC Report shall contain the following items:

(a) Identification of the submitter of the Revision Request;

(b) Modified Revision Request language proposed by TAC, if applicable;

(c) Identification of the authorship of comments;

(d) Proposed effective date(s) of the Revision Request;

(e) Priority and rank for any Revision Requests requiring an ERCOT project for implementation;

(f) PRS action;

(g) TAC action; and

(h) ERCOT's position on the Revision Request.

(5) If TAC recommends approval of a Revision Request, ERCOT shall forward the TAC Report to the ERCOT Board for consideration pursuant to Section 21.4.10, ERCOT Board Vote.

21.4.9 ERCOT Impact Analysis Based on Technical Advisory Committee Report

(1) ERCOT shall review the TAC Report and, if necessary, update the Impact Analysis as soon as practicable. ERCOT shall distribute the updated Impact Analysis, if applicable, to TAC and post it on the ERCOT website. If a longer review period is required for ERCOT to update the Impact Analysis, ERCOT shall submit comments with a schedule for completion of the Impact Analysis.

21.4.10 ERCOT Board Vote

(1) Upon issuance of a TAC Report and Impact Analysis to the ERCOT Board, the ERCOT Board shall review the TAC Report and the Impact Analysis at the next regularly scheduled meeting. For Urgent Revision Requests, the ERCOT Board shall review the TAC Report and Impact Analysis at the next regularly scheduled meeting, unless a special meeting is required due to the urgency of the Revision Request.

(2) The quorum and voting requirements for ERCOT Board action are set forth in the ERCOT Bylaws. In considering action on a TAC Report, the ERCOT Board shall:

(a) Approve the Revision Request as recommended in the TAC Report or as modified by the ERCOT Board;

(b) Reject the Revision Request;

(c) Defer decision on the Revision Request; or

(d) Remand the Revision Request to TAC with instructions.

(3) If a motion is made to approve a Revision Request and that motion fails, the Revision Request shall be deemed rejected by the ERCOT Board unless at the same meeting the

ERCOT Board later votes to approve, defer, or remand the Revision Request. The rejected Revision Request shall be subject to appeal pursuant to Section 21.4.11.3, Appeal of ERCOT Board Action.

(4) Within three Business Days after the ERCOT Board takes action on a Revision Request, ERCOT shall post a Board Report reflecting the ERCOT Board action on the ERCOT website.

21.4.11 Appeal of Action

(1) The following processes are to be used to appeal an action related to a Revision Request.

21.4.11.1 Appeal of Protocol Revision Subcommittee Action

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the IMM, the NERC Regional Entity, or ERCOT may appeal a PRS action to reject, defer or refer a Revision Request, directly to the TAC. Such appeal to the TAC must be submitted electronically to ERCOT by completing the designated form provided on the ERCOT website within seven days after the date of the relevant PRS appealable event. ERCOT shall reject appeals made after that time. ERCOT shall post appeals on the ERCOT website within three Business Days of receiving the appeal. Appeals shall be heard at the next regularly scheduled TAC meeting that is at least seven days after the date of the requested appeal. An appeal of a Revision Request to TAC suspends consideration of the Revision Request until the appeal has been decided by TAC.

21.4.11.2 Appeal of Technical Advisory Committee Action

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the IMM, the NERC Regional Entity, or ERCOT may appeal a TAC action to reject, defer, remand or refer a Revision Request directly to the ERCOT Board. Appeals to the ERCOT Board shall be processed in accordance with the ERCOT Board Policies and Procedures. An appeal of a Revision Request to the ERCOT Board suspends consideration of the Revision Request until the appeal has been decided by the ERCOT Board.

21.4.11.3 Appeal of ERCOT Board Action

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the IMM, or the NERC Regional Entity may appeal any decision of the ERCOT Board regarding a Revision Request to the PUCT or other Governmental Authority. Such appeal to the PUCT or other Governmental Authority must be made within any deadline prescribed by the PUCT or other Governmental Authority, but in any event no later than 35 days of the date of the relevant ERCOT Board appealable event. Notice of any appeal to the PUCT or other Governmental Authority must be provided, at the time of the

appeal, to ERCOT's General Counsel. If the PUCT or other Governmental Authority rules on the Revision Request, ERCOT shall post the ruling on the ERCOT website.

21.5 Urgent and Board Priority Nodal Protocol Revision Requests and System Change Requests

(1) The party submitting a Nodal Protocol Revision Request (NPRR) or System Change Request (SCR) ("Revision Request") may request that the Revision Request be considered on an urgent timeline ("Urgent") only when the submitter can reasonably show that an existing Protocol or condition is impairing or could imminently impair ERCOT System reliability or wholesale or retail market operations, or is causing or could imminently cause a discrepancy between a settlement formula and a provision of these Protocols.

(2) The Protocol Revision Subcommittee (PRS) may designate the Revision Request for Urgent consideration upon a valid motion in a regularly scheduled meeting of the PRS or at a special meeting called by the PRS leadership. Criteria for designating a Revision Request as Urgent are that the Revision Request requires immediate attention due to:

(a) Serious concerns about ERCOT System reliability or market operations under the unmodified language or existing conditions; or

(b) The crucial nature of settlement activity conducted pursuant to any settlement formula.

(3) The ERCOT Board may designate any existing Revision Request a Board Priority Revision Request. If the ERCOT Board directs ERCOT Staff to file a Revision Request, it may further direct that a Revision Request be designated a Board Priority Revision Request. All Board Priority Revision Requests will be considered on an Urgent timeline.

(4) ERCOT shall prepare an Impact Analysis for Urgent and Board Priority Revision Requests as soon as practicable.

(5) The PRS shall consider the Urgent or Board Priority Revision Request and Impact Analysis, if available, at its next regularly scheduled meeting, or at a special meeting called by the PRS leadership to consider the Urgent or Board Priority Revision Request.

(6) If recommended for approval by PRS, ERCOT shall post a PRS Report on the ERCOT website within three Business Days after PRS takes action. The TAC chair may request action from TAC to accelerate or alter the procedures described herein, as needed, to address the urgency of the situation.

(7) Any Urgent or Board Priority Revision Requests shall be subject to an Impact Analysis pursuant to Section 21.4.9, ERCOT Impact Analysis Based on Technical Advisory Committee Report, and ERCOT Board consideration pursuant to Section 21.4.10, ERCOT Board Vote.

21.6 Nodal Protocol Revision Implementation

(1) Upon ERCOT Board approval, ERCOT shall implement Nodal Protocol Revision Requests (NPRRs) on the first day of the month following ERCOT Board approval, unless otherwise provided in the Board Report for the approved NPRR.

(2) For such other NPRRs, the Impact Analysis shall provide an estimated amount of time required to implement the NPRR and ERCOT shall provide notice as soon as practicable, but no later than ten days prior to actual implementation, unless a different notice period is required in the Board Report for the approved NPRR.

(3) If the ERCOT Board approves changes to the Protocols, such changes shall be:

(a) Filed with the Public Utility Commission of Texas (PUCT) for informational purposes as soon as practicable, but no later than one day before the effective date of the changes; and

(b) Incorporated into the Protocols and posted on the ERCOT website as soon as practicable, but no later than one day before the effective date of the changes.

(4) ERCOT shall implement an Administrative NPRR on the first day of the month following the end of the ten Business Day posting requirement outlined in Section 21.1, Introduction.

21.7 Review of Project Prioritization and Annual Budget Process

(1) The Protocol Revision Subcommittee (PRS) shall recommend to the Technical Advisory Committee (TAC) an assignment of a project priority for each approved Nodal Protocol Revision Request (NPRR) and System Change Request (SCR) (“Revision Request”) that requires an associated project.

(2) Annually during the ERCOT budget process, the PRS shall review the priority of all market-requested projects and recommend new or revised project priorities for market-requested projects.

(3) TAC shall consider the project priority of each Revision Request and make recommendations to the ERCOT Board.

(4) The ERCOT Board shall take one of the following actions regarding the project prioritization recommended by TAC:

(a) Approve the TAC recommendation as originally submitted or as modified by the ERCOT Board;

(b) Reject the TAC recommendation;

(c) Remand the TAC recommendation to TAC with instructions; or

(d) Defer consideration of the TAC recommendation.

21.8 Review of Guide Changes

(1) The revision process for the ERCOT market guides shall be governed by the individual guides and assigned subcommittees. The Protocol Revision Subcommittee (PRS) shall review changes to market guides proposed by other subcommittees that may conflict with existing Protocols and report the results of its review to the submitting subcommittee.

ERCOT Nodal Protocols

Section 22

Attachment A: Standard Form Market Participant Agreement

April 1, 2022

Standard Form Market Participant Agreement
Between
Insert Participant
and
Electric Reliability Council of Texas, Inc.

This Market Participant Agreement ("Agreement"), effective as of the___________ day of _______________,___________ ("Effective Date"), is entered into by and between Insert Participant, a [Insert State of Registration and Entity type] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS:

A. As defined in the ERCOT Protocols, Participant is a (check all that apply):

☐ Load Serving Entity (LSE)

☐ Qualified Scheduling Entity (QSE)

☐ Transmission Service Provider (TSP)

☐ Distribution Service Provider (DSP)

☐ Congestion Revenue Right (CRR) Account Holder

☐ Resource Entity

☐ Renewable Energy Credit (REC) Account Holder

☐ Independent Market Information System Registered Entity (IMRE)

B. ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region; and

C. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the "Parties") hereby agree as follows:

Section 1. Notice.

All notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three (3) days after being deposited in the U.S. mail, first class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or overnight delivery service. Either Party may change its address for such notices by delivering to the other Party a written notice referring specifically to this Agreement. Notices required under the ERCOT Protocols shall be in accordance with the applicable Section of the ERCOT Protocols.

If to ERCOT:

Electric Reliability Council of Texas, Inc.
Attn: Legal Department
8000 Metropolis Drive (Building E), Suite 100
Austin, Texas 78744
Telephone: (512) 225-7000
Facsimile: (512) 225-7079

If to Participant:

[Insert Participant Name]
[Insert Contact Person/Dept.]
[Insert Street Address]
[Insert City, State Zip]
[Insert Telephone]
[Insert Facsimile]

Section 2. Definitions.

A. Unless herein defined, all definitions and acronyms found in the ERCOT Protocols shall be incorporated by reference into this Agreement.

B. “ERCOT Protocols” shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and Settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. For the purposes of determining responsibilities and rights at a given time, the ERCOT Protocols, as amended in accordance with the change procedure(s) described in the ERCOT Protocols, in effect at the time of the performance or non-performance of an action, shall govern with respect to that action.

Section 3. Term and Termination.

A. Term. The initial term ("Initial Term") of this Agreement shall commence on the Effective Date and continue until the last day of the month which is twelve (12) months from the Effective Date. After the Initial Term, this Agreement shall automatically renew for one-year terms (a "Renewal Term") unless the standard form of this Agreement contained in the ERCOT Protocols has been modified by a change to the ERCOT Protocols. If the standard form of this Agreement has been so modified, then this Agreement will terminate upon the effective date of the replacement agreement This Agreement may also be terminated during the Initial Term or the then-current Renewal Term in accordance with this Agreement.

B. Termination by Participant. Participant may, at its option, terminate this Agreement:

(1) Immediately upon the failure of ERCOT to continue to be certified by the PUCT as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151;

(2) If the "REC Account Holder" box is checked in Section A. of the *Recitals* section of this Agreement, Participant may, at its option, terminate this Agreement immediately if the PUCT ceases to certify ERCOT as the Entity approved by the PUCT ("Program Administrator") for carrying out the administrative responsibilities related to the Renewable Energy Credit Program as set forth in PUC Substantive Rule 25.173(g) without the immediate certification of another Program Administrator under PURA §39.151; or

(3) For any other reason at any time upon thirty days written notice to ERCOT.

C. Effect of Termination and Survival of Terms. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.

Section 4. Representations, Warranties, and Covenants.

A. Participant represents, warrants, and covenants that:

(1) Participant is duly organized, validly existing and in good standing under the laws of the jurisdiction under which it is organized and is authorized to do business in Texas;

(2) Participant has full power and authority to enter into this Agreement and perform all obligations, representations, warranties and covenants under this Agreement;

(3) Participant's past, present and future agreements or Participant's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which Participant is a party or by which its assets or properties are bound do not materially affect performance of Participant's obligations under this Agreement;

(4) Market Participant's execution, delivery and performance of this Agreement by Participant have been duly authorized by all requisite action of its governing body;

(5) Except as set out in an exhibit (if any) to this Agreement, ERCOT has not, within the twenty-four (24) months preceding the Effective Date, terminated for Default any Prior Agreement with Participant, any company of which Participant is a successor in interest, or any Affiliate of Participant;

(6) If any Defaults are disclosed on any such exhibit mentioned in subsection 4(A)(5), either (a) ERCOT has been paid, before execution of this Agreement, all sums due to it in relation to such Prior Agreement, or (b) ERCOT, in its reasonable judgment, has determined that this Agreement is necessary for system reliability and Participant has made alternate arrangements satisfactory to ERCOT for the resolution of the Default under the Prior Agreement;

(7) Participant has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(8) Participant is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(9) Participant is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt;

(10) Participant acknowledges that it has received and is familiar with the ERCOT Protocols; and

(11) Participant acknowledges and affirms that the foregoing representations, warranties and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, "materially affecting performance" means resulting in a materially adverse effect on Participant's performance of its obligations under this Agreement.

B. <u>ERCOT represents, warrants and covenants that:</u>

(1) ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;

(2) ERCOT is duly organized, validly existing and in good standing under the laws of Texas, and is authorized to do business in Texas;

(3) ERCOT has full power and authority to enter into this Agreement and perform all of ERCOT's obligations, representations, warranties and covenants under this Agreement;

(4) ERCOT's past, present and future agreements or ERCOT's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which ERCOT is a party or by which its assets or properties are bound do not materially affect performance of ERCOT's obligations under this Agreement;

(5) The execution, delivery and performance of this Agreement by ERCOT have been duly authorized by all requisite action of its governing body;

(6) ERCOT has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(7) ERCOT is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(8) ERCOT is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt; and

(9) ERCOT acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, "materially affecting performance" means resulting in a materially adverse effect on ERCOT's performance of its obligations under this Agreement.

Section 5. Participant Obligations.

A. Participant shall comply with, and be bound by, all ERCOT Protocols.

B. Participant shall not take any action, without first providing written notice to ERCOT and reasonable time for ERCOT and Market Participants to respond, that would cause a Market Participant within the ERCOT Region that is not a "public utility" under the Federal Power Act or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission.

Section 6. ERCOT Obligations.

A. ERCOT shall comply with, and be bound by, all ERCOT Protocols.

B. ERCOT shall not take any action, without first providing written notice to Participant and reasonable time for Participant and other Market Participants to respond, that would cause Participant, if Participant is not a "public utility" under the Federal Power Act, or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission. If ERCOT receives any notice similar to that described in Section 5(B) from any Market Participant, ERCOT shall provide notice of same to Participant.

Section 7. [RESERVED]

Section 8. Default.

A. Event of Default.

(1) Failure by Participant to (i) pay when due, any payment or Financial Security obligation owed to ERCOT or its designee, if applicable, under any agreement with ERCOT ("Payment Breach"), or (ii) designate/maintain an association with a QSE (if required by the ERCOT Protocols) ("QSE Affiliation Breach"), shall constitute a material breach and event of default ("Default") unless cured within one (1) Bank Business Day after ERCOT delivers written notice of the breach to Participant. Provided further that if such a material breach, regardless of whether the breaching Party cures the breach within the allotted time after notice of the material breach, occurs more than three (3) times in a 12-month period, the fourth such breach shall constitute a Default.

(2) A material breach other than a Payment Breach or a QSE Affiliation Breach includes any material failure by Participant to comply with the ERCOT Protocols. A material breach under this subsection shall constitute an event of Default by Participant unless cured within fourteen (14) Business Days after delivery by ERCOT of written notice of the material breach to Participant. Participant must begin work or other efforts within three (3) Business Days to cure such material breach after delivery of the breach notice by ERCOT, and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times in a 12-month period, the fourth such breach shall constitute a Default.

A material breach under this subsection shall not result in a Default if the breach cannot reasonably be cured within fourteen (14) Business Days, and Participant:

(a) Promptly provides ERCOT with written notice of the reasons why the breach cannot reasonably be cured within fourteen (14) Business Days;

(b) Begins to work or other efforts to cure the breach within three (3) Business Days after ERCOT's delivery of the notice to Participant; and

(c) Prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(3) Bankruptcy by Participant, except for the filing of a petition in involuntary bankruptcy or similar involuntary proceedings, that is dismissed within 90 days thereafter, shall constitute an event of Default.

(4) Except as otherwise excused herein, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a Payment Breach, shall constitute a Default by ERCOT unless cured within fourteen (14) Business Days after delivery by Participant of written notice of the material breach to ERCOT. ERCOT must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by Participant of written notice of such material breach by ERCOT and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a 12-month period, the fourth such breach shall constitute a Default.

(5) If, due to a Force Majeure Event, a Party is in breach with respect to any obligation hereunder, such breach shall not result in a Default by that Party.

B. <u>Remedies for Default.</u>

(1) <u>ERCOT's Remedies for Default.</u> In the event of a Default by Participant, ERCOT may pursue any remedies ERCOT has under this Agreement, at law, or in equity, subject to the provisions of Section 10: Dispute Resolution of this Agreement. In the event of a Default by Participant, if the ERCOT Protocols do not specify a remedy for a particular Default, ERCOT may, at its option, upon written notice to Participant, immediately terminate this Agreement, with termination to be effective upon the date of delivery of notice. In the event of Participant's bankruptcy, Participant waives any right to challenge ERCOT's right to set off amounts ERCOT owes to Participant by the amount of any sums owed by Participant to ERCOT, including any amounts owed pursuant to the operation of the Protocols.

(2) <u>Participant's Remedies for Default.</u>

(a) Unless otherwise specified in this Agreement or in the ERCOT Protocols, and subject to the provisions of Section 10: Dispute Resolution of this Agreement in the event of a Default by ERCOT, Participant's remedies shall be limited to:

(i) Immediate termination of this Agreement upon written notice to ERCOT;

(ii) Monetary recovery in accordance with the Settlement procedures set forth in the ERCOT Protocols; and

(iii) Specific performance.

(b) However, in the event of a material breach by ERCOT of any of its representations, warranties or covenants, Participant's sole remedy shall be immediate termination of this Agreement upon written notice to ERCOT.

(3) A Default or breach of this Agreement by a Party shall not relieve either Party of the obligation to comply with the ERCOT Protocols.

C. Force Majeure.

(1) If, due to a Force Majeure Event, either Party is in breach of this Agreement with respect to any obligation hereunder, such Party shall take reasonable steps, consistent with Good Utility Practice, to remedy such breach. If either Party is unable to fulfill any obligation by reason of a Force Majeure Event, it shall give notice and the full particulars of the obligations affected by such Force Majeure Event to the other Party in writing or by telephone (if followed by written notice) as soon as reasonably practicable, but not later than fourteen (14) calendar days, after such Party becomes aware of the event. A failure to give timely notice of the Force Majeure event shall constitute a waiver of the claim of Force Majeure Event. The Party experiencing the Force Majeure Event shall also provide notice, as soon as reasonably practicable, when the Force Majeure Event ends.

(2) Notwithstanding the foregoing, a Force Majeure Event does not relieve a Party affected by a Force Majeure Event of its obligation to make payments or of any consequences of non-performance pursuant to the ERCOT Protocols or under this Agreement, except that the excuse from Default provided by subsection 8(A)(5) above is still effective.

D. Duty to Mitigate. Except as expressly provided otherwise herein, each Party shall use commercially reasonable efforts to mitigate any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Section 9. Limitation of Damages and Liability and Indemnification.

A. EXCEPT AS EXPRESSLY LIMITED IN THIS AGREEMENT OR THE ERCOT PROTOCOLS, ERCOT OR PARTICIPANT MAY SEEK FROM THE OTHER, THROUGH APPLICABLE DISPUTE RESOLUTION PROCEDURES SET FORTH IN THE ERCOT PROTOCOLS, ANY MONETARY DAMAGES OR OTHER REMEDY OTHERWISE ALLOWABLE UNDER TEXAS LAW, AS DAMAGES FOR DEFAULT OR BREACH OF THE OBLIGATIONS UNDER THIS AGREEMENT; PROVIDED, HOWEVER, THAT NEITHER PARTY IS LIABLE TO THE OTHER FOR ANY SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY THAT MAY OCCUR, IN WHOLE OR IN PART, AS A RESULT OF A DEFAULT UNDER THIS AGREEMENT, A TORT, OR ANY OTHER CAUSE, WHETHER OR

NOT A PARTY HAD KNOWLEDGE OF THE CIRCUMSTANCES THAT RESULTED IN THE SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY, OR COULD HAVE FORESEEN THAT SUCH DAMAGES OR INJURY WOULD OCCUR.

B. With respect to any dispute regarding a Default or breach by ERCOT of its obligations under this Agreement, ERCOT expressly waives any Limitation of Liability to which it may be entitled under the Charitable Immunity and Liability Act of 1987, Tex. Civ. Prac. & Rem. Code §84.006, or successor statute.

C. The Parties have expressly agreed that, other than subsections A and B of this Section, this Agreement shall not include any other limitations of liability or indemnification provisions, and that such issues shall be governed solely by applicable law, in a manner consistent with the Choice of Law and Venue subsection of this Agreement, regardless of any contrary provisions that may be included in or subsequently added to the ERCOT Protocols (outside of this Agreement).

D. The Independent Market Monitor (IMM), and its directors, officers, employees, and agents, shall not be liable to any person or Entity for any act or omission, other than an act or omission constituting gross negligence or intentional misconduct, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual, direct, indirect, or consequential damages of any kind resulting from or attributable to any such act or omission of the IMM, as long as such act or omission arose from or is related to matters within the scope of the IMM's authority arising under or relating to PURA §39.1515 and PUC SUBST. R. 25.365, Independent Market Monitor.

Section 10. Dispute Resolution.

A. In the event of a dispute, including a dispute regarding a Default, under this Agreement, Parties to this Agreement shall first attempt resolution of the dispute using the applicable dispute resolution procedures set forth in the ERCOT Protocols.

B. In the event of a dispute, including a dispute regarding a Default, under this Agreement, each Party shall bear its own costs and fees, including, but not limited to attorneys' fees, court costs, and its share of any mediation or arbitration fees.

Section 11. Miscellaneous.

A. Choice of Law and Venue. Notwithstanding anything to the contrary in this Agreement, this Agreement shall be deemed entered into and performable solely in Texas and, with the exception of matters governed exclusively by federal law, shall be governed by and construed and interpreted in accordance with the laws of the State of Texas that apply to contracts executed in and performed entirely within the State of Texas, without reference to any rules of conflict of laws. Neither Party waives primary jurisdiction as a defense; provided that any court suits regarding this Agreement shall be brought in a state or federal court located within Travis County, Texas, and the Parties hereby waive any defense of forum non-conveniens, except defenses under Tex. Civ. Prac. & Rem. Code §15.002(b).

B. Assignment.

(1) Notwithstanding anything herein to the contrary, a Party shall not assign or otherwise transfer all or any of its rights or obligations under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld or delayed, except that a Party may assign or transfer its rights and obligations under this Agreement without the prior written consent of the other Party (if neither the assigning Party or the assignee is then in Default of any Agreement with ERCOT):

(a) Where any such assignment or transfer is to an Affiliate of the Party; or

(b) Where any such assignment or transfer is to a successor to or transferee of the direct or indirect ownership or operation of all or part of the Party, or its facilities; or

(c) For collateral security purposes to aid in providing financing for itself, provided that the assigning Party will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by either Party pursuant to this Section will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). If requested by the Party making any such collateral assignment to a Financing Person, the other Party shall execute and deliver a consent to such assignment containing customary provisions, including representations as to corporate authorization, enforceability of this Agreement and absence of known Defaults, notice of material breach pursuant to Section 8(A), notice of Default, and an opportunity for the Financing Person to cure a material breach pursuant to Section 8(A) prior to it becoming a Default.

(2) An assigning Party shall provide prompt written notice of the assignment to the other Party. Any attempted assignment that violates this Section is void and ineffective. Any assignment under this Agreement shall not relieve either Party of its obligations under this Agreement, nor shall either Party's obligations be enlarged, in whole or in part, by reason thereof.

C. No Third Party Beneficiary. Except with respect to the rights of the Financing Persons in Section 11(B), (a) nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, (b) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (c) this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to this Agreement or the services to be provided hereunder. Nothing in this Agreement shall create a contractual relationship between one

Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

D. No Waiver. Parties shall not be required to give notice to enforce strict adherence to all provisions of this Agreement. No breach or provision of this Agreement shall be deemed waived, modified or excused by a Party unless such waiver, modification or excuse is in writing and signed by an authorized officer of such Party. The failure by or delay of either Party in enforcing or exercising any of its rights under this Agreement shall (a) not be deemed a waiver, modification or excuse of such right or of any breach of the same or different provision of this Agreement, and (b) not prevent a subsequent enforcement or exercise of such right. Each Party shall be entitled to enforce the other Party's covenants and promises contained herein, notwithstanding the existence of any claim or cause of action against the enforcing Party under this Agreement or otherwise.

E. Headings. Titles and headings of paragraphs and sections within this Agreement are provided merely for convenience and shall not be used or relied upon in construing this Agreement or the Parties' intentions with respect thereto.

F. Severability. In the event that any of the provisions, or portions or applications thereof, of this Agreement is finally held to be unenforceable or invalid by any court of competent jurisdiction, that determination shall not affect the enforceability or validity of the remaining portions of this Agreement, and this Agreement shall continue in full force and effect as if it had been executed without the invalid provision; provided, however, if either Party determines, in its sole discretion, that there is a material change in this Agreement by reason thereof, the Parties shall promptly enter into negotiations to replace the unenforceable or invalid provision with a valid and enforceable provision. If the Parties are not able to reach an agreement as the result of such negotiations within fourteen (14) days, either Party shall have the right to terminate this Agreement on three (3) days written notice.

G. Entire Agreement. Any exhibits attached to this Agreement are incorporated into this Agreement by reference and made a part of this Agreement as if repeated verbatim in this Agreement. This Agreement represents the Parties' final and mutual understanding with respect to its subject matter. It replaces and supersedes any prior agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by any Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement. An agreement, statement, or promise not contained in this Agreement is not valid or binding.

H. Amendment. The standard form of this Agreement may only be modified through the procedure for modifying ERCOT Protocols described in the ERCOT Protocols. Any changes to the terms of the standard form of this Agreement shall not take effect until a new Agreement is executed between the Parties.

I. ERCOT's Right to Audit Participant. Participant shall keep detailed records for a period of three years of all activities under this Agreement giving rise to any information, statement, charge, payment or computation delivered to ERCOT under the ERCOT

Protocols. Such records shall be retained and shall be available for audit or examination by ERCOT as hereinafter provided. ERCOT has the right during Business Hours and upon reasonable written notice and for reasonable cause to examine the records of Participant as necessary to verify the accuracy of any such information, statement, charge, payment or computation made under this Agreement. If any such examination reveals any inaccuracy in any such information, statement, charge, payment or computation, the necessary adjustments in such information, statement, charge, payment, computation, or procedures used in supporting its ongoing accuracy will be promptly made.

J. Participant's Right to Audit ERCOT. Participant's right to data and audit of ERCOT shall be as described in the ERCOT Protocols and shall not exceed the rights described in the ERCOT Protocols.

K. Further Assurances. Each Party agrees that during the term of this Agreement it will take such actions, provide such documents, do such things and provide such further assurances as may reasonably be requested by the other Party to permit performance of this Agreement.

L. Conflicts. This Agreement is subject to applicable federal, state, and local laws, ordinances, rules, regulations, orders of any Governmental Authority and tariffs. Nothing in this Agreement may be construed as a waiver of any right to question or contest any federal, state and local law, ordinance, rule, regulation, order of any Governmental Authority, or tariff. In the event of a conflict between this Agreement and an applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff, the applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff shall prevail, provided that Participant shall give notice to ERCOT of any such conflict affecting Participant. In the event of a conflict between the ERCOT Protocols and this Agreement, the provisions expressly set forth in this Agreement shall control.

M. No Partnership. This Agreement may not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party has any right, power, or authority to enter any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

N. Construction. In this Agreement, the following rules of construction apply, unless expressly provided otherwise or unless the context clearly requires otherwise:

(1) The singular includes the plural, and the plural includes the singular.

(2) The present tense includes the future tense, and the future tense includes the present tense.

(3) Words importing any gender include the other gender.

(4) The word "shall" denotes a duty.

(5) The word "must" denotes a condition precedent or subsequent.

(6) The word "may" denotes a privilege or discretionary power.

(7) The phrase "may not" denotes a prohibition.

(8) References to statutes, tariffs, regulations or ERCOT Protocols include all provisions consolidating, amending, or replacing the statutes, tariffs, regulations or ERCOT Protocols referred to.

(9) References to "writing" include printing, typing, lithography, and other means of reproducing words in a tangible visible form.

(10) The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(11) Any reference to a day, week, month or year is to a calendar day, week, month or year unless otherwise indicated.

(12) References to articles, Sections (or subdivisions of Sections), exhibits, annexes or schedules are to this Agreement, unless expressly stated otherwise.

(13) Unless expressly stated otherwise, references to agreements, ERCOT Protocols and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent the amendments and other modifications are not prohibited by this Agreement.

(14) References to persons or entities include their respective successors and permitted assigns and, for governmental entities, entities succeeding to their respective functions and capacities.

(15) References to time are to Central Prevailing Time.

O. Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.

Electric Reliability Council of Texas, Inc.:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Participant:

By:_______________________________

Name:

Title:

Date:

Market Participant Name:

Market Participant DUNS:

[NPRR857: Replace Section 22 Attachment A above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Standard Form Market Participant Agreement
Between
Participant
and
Electric Reliability Council of Texas, Inc.

This Market Participant Agreement ("Agreement"), effective as of the___________ day of _______________,___________ ("Effective Date"), is entered into by and between [Participant], a [State of Registration and Entity type] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS:

A. As defined in the ERCOT Protocols, Participant is a (check all that apply):

☐ Load Serving Entity (LSE)

☐ Qualified Scheduling Entity (QSE)

☐ Transmission Service Provider (TSP)

☐ Distribution Service Provider (DSP)

☐ Congestion Revenue Right (CRR) Account Holder

☐ Resource Entity

☐ Renewable Energy Credit (REC) Account Holder

☐ Independent Market Information System Registered Entity (IMRE)

☐ Direct Current Tie Operator (DCTO)

B. ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region; and

C. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the "Parties") hereby agree as follows:

Section 1. Notice.

All notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three (3) days after being deposited in the U.S. mail, first class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or overnight delivery service. Either Party may change its address for such notices by delivering to the other Party a written notice referring specifically to this Agreement. Notices required under the ERCOT Protocols shall be in accordance with the applicable Section of the ERCOT Protocols.

If to ERCOT:

Electric Reliability Council of Texas, Inc.
Attn: Legal Department
8000 Metropolis Drive (Building E), Suite 100
Austin, Texas 78744
Telephone: (512) 225-7000
Facsimile: (512) 225-7079

If to Participant:

[Participant Name]

[Contact Person/Dept.]

[Street Address]

[City, State Zip]

[Telephone]

[Facsimile]

Section 2. Definitions.

A. Unless herein defined, all definitions and acronyms found in the ERCOT Protocols shall be incorporated by reference into this Agreement.

B. "ERCOT Protocols" shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and Settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. For the purposes of determining responsibilities and rights at a given time, the ERCOT Protocols, as amended in accordance with the change procedure(s) described in the ERCOT Protocols, in effect at the time of the performance or non-performance of an action, shall govern with respect to that action.

Section 3. Term and Termination.

A. Term. The initial term ("Initial Term") of this Agreement shall commence on the Effective Date and continue until the last day of the month which is twelve (12) months from the Effective Date. After the Initial Term, this Agreement shall automatically renew for one-year terms (a "Renewal Term") unless the standard form of this Agreement contained in the ERCOT Protocols has been modified by a change to the ERCOT Protocols. If the standard form of this Agreement has been so modified, then this Agreement will terminate upon the effective date of the replacement agreement This Agreement may also be terminated during the Initial Term or the then-current Renewal Term in accordance with this Agreement.

B. Termination by Participant. Participant may, at its option, terminate this Agreement:

(1) Immediately upon the failure of ERCOT to continue to be certified by the PUCT as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151;

(2) If the "REC Account Holder" box is checked in Section A. of the *Recitals* section of this Agreement, Participant may, at its option, terminate this Agreement immediately if the PUCT ceases to certify ERCOT as the Entity approved by the PUCT ("Program Administrator") for carrying out the administrative responsibilities related to the Renewable Energy Credit Program as set forth in PUC Substantive Rule 25.173(g) without the immediate certification of another Program Administrator under PURA §39.151; or

(3) For any other reason at any time upon thirty days written notice to ERCOT.

C. Effect of Termination and Survival of Terms. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.

Section 4. Representations, Warranties, and Covenants.

A. Participant represents, warrants, and covenants that:

(1) Participant is duly organized, validly existing and in good standing under the laws

of the jurisdiction under which it is organized and is authorized to do business in Texas;

(2) Participant has full power and authority to enter into this Agreement and perform all obligations, representations, warranties and covenants under this Agreement;

(3) Participant's past, present and future agreements or Participant's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which Participant is a party or by which its assets or properties are bound do not materially affect performance of Participant's obligations under this Agreement;

(4) Market Participant's execution, delivery and performance of this Agreement by Participant have been duly authorized by all requisite action of its governing body;

(5) Except as set out in an exhibit (if any) to this Agreement, ERCOT has not, within the twenty-four (24) months preceding the Effective Date, terminated for Default any Prior Agreement with Participant, any company of which Participant is a successor in interest, or any Affiliate of Participant;

(6) If any Defaults are disclosed on any such exhibit mentioned in subsection 4(A)(5), either (a) ERCOT has been paid, before execution of this Agreement, all sums due to it in relation to such Prior Agreement, or (b) ERCOT, in its reasonable judgment, has determined that this Agreement is necessary for system reliability and Participant has made alternate arrangements satisfactory to ERCOT for the resolution of the Default under the Prior Agreement;

(7) Participant has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(8) Participant is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(9) Participant is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt;

(10) Participant acknowledges that it has received and is familiar with the ERCOT Protocols; and

(11) Participant acknowledges and affirms that the foregoing representations, warranties and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, "materially affecting performance"

means resulting in a materially adverse effect on Participant's performance of its obligations under this Agreement.

B. ERCOT represents, warrants and covenants that:

(1) ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;

(2) ERCOT is duly organized, validly existing and in good standing under the laws of Texas, and is authorized to do business in Texas;

(3) ERCOT has full power and authority to enter into this Agreement and perform all of ERCOT's obligations, representations, warranties and covenants under this Agreement;

(4) ERCOT's past, present and future agreements or ERCOT's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which ERCOT is a party or by which its assets or properties are bound do not materially affect performance of ERCOT's obligations under this Agreement;

(5) The execution, delivery and performance of this Agreement by ERCOT have been duly authorized by all requisite action of its governing body;

(6) ERCOT has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(7) ERCOT is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(8) ERCOT is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt; and

(9) ERCOT acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, "materially affecting performance" means resulting in a materially adverse effect on ERCOT's performance of its obligations under this Agreement.

Section 5. Participant Obligations.

A. Participant shall comply with, and be bound by, all ERCOT Protocols.

B. Participant shall not take any action, without first providing written notice to ERCOT and reasonable time for ERCOT and Market Participants to respond, that would cause a Market Participant within the ERCOT Region that is not a "public utility" under the Federal Power Act or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission.

Section 6. ERCOT Obligations.

A. ERCOT shall comply with, and be bound by, all ERCOT Protocols.

B. ERCOT shall not take any action, without first providing written notice to Participant and reasonable time for Participant and other Market Participants to respond, that would cause Participant, if Participant is not a "public utility" under the Federal Power Act, or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission. If ERCOT receives any notice similar to that described in Section 5(B) from any Market Participant, ERCOT shall provide notice of same to Participant.

Section 7. [RESERVED]

Section 8. Default.

A. Event of Default.

(1) Failure by Participant to (i) pay when due, any payment or Financial Security obligation owed to ERCOT or its designee, if applicable, under any agreement with ERCOT ("Payment Breach"), or (ii) designate/maintain an association with a QSE (if required by the ERCOT Protocols) ("QSE Affiliation Breach"), shall constitute a material breach and event of default ("Default") unless cured within one (1) Bank Business Day after ERCOT delivers written notice of the breach to Participant. Provided further that if such a material breach, regardless of whether the breaching Party cures the breach within the allotted time after notice of the material breach, occurs more than three (3) times in a 12-month period, the fourth such breach shall constitute a Default.

(2) A material breach other than a Payment Breach or a QSE Affiliation Breach includes any material failure by Participant to comply with the ERCOT Protocols. A material breach under this subsection shall constitute an event of Default by Participant unless cured within fourteen (14) Business Days after delivery by ERCOT of written notice of the material breach to Participant. Participant must begin work or other efforts within three (3) Business Days to cure such material breach after delivery of the breach notice by ERCOT, and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times in a 12-month period, the fourth such breach shall constitute a

Default.

A material breach under this subsection shall not result in a Default if the breach cannot reasonably be cured within fourteen (14) Business Days, and Participant:

(a) Promptly provides ERCOT with written notice of the reasons why the breach cannot reasonably be cured within fourteen (14) Business Days;

(b) Begins to work or other efforts to cure the breach within three (3) Business Days after ERCOT's delivery of the notice to Participant; and

(c) Prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(3) Bankruptcy by Participant, except for the filing of a petition in involuntary bankruptcy or similar involuntary proceedings, that is dismissed within 90 days thereafter, shall constitute an event of Default.

(4) Except as otherwise excused herein, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a Payment Breach, shall constitute a Default by ERCOT unless cured within fourteen (14) Business Days after delivery by Participant of written notice of the material breach to ERCOT. ERCOT must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by Participant of written notice of such material breach by ERCOT and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a 12-month period, the fourth such breach shall constitute a Default.

(5) If, due to a Force Majeure Event, a Party is in breach with respect to any obligation hereunder, such breach shall not result in a Default by that Party.

B. Remedies for Default.

(1) ERCOT's Remedies for Default. In the event of a Default by Participant, ERCOT may pursue any remedies ERCOT has under this Agreement, at law, or in equity, subject to the provisions of Section 10: Dispute Resolution of this Agreement. In the event of a Default by Participant, if the ERCOT Protocols do not specify a remedy for a particular Default, ERCOT may, at its option, upon written notice to Participant, immediately terminate this Agreement, with termination to be effective upon the date of delivery of notice. In the event of Participant's bankruptcy, Participant waives any right to challenge ERCOT's right to set off amounts ERCOT owes to Participant by the amount of any sums owed by Participant to ERCOT, including any amounts owed pursuant to the operation of the Protocols.

(2) Participant's Remedies for Default.

(a) Unless otherwise specified in this Agreement or in the ERCOT Protocols, and subject to the provisions of Section 10: Dispute Resolution of this Agreement in the event of a Default by ERCOT, Participant's remedies shall be limited to:

(i) Immediate termination of this Agreement upon written notice to ERCOT;

(ii) Monetary recovery in accordance with the Settlement procedures set forth in the ERCOT Protocols; and

(iii) Specific performance.

(b) However, in the event of a material breach by ERCOT of any of its representations, warranties or covenants, Participant's sole remedy shall be immediate termination of this Agreement upon written notice to ERCOT.

(3) A Default or breach of this Agreement by a Party shall not relieve either Party of the obligation to comply with the ERCOT Protocols.

C. Force Majeure.

(1) If, due to a Force Majeure Event, either Party is in breach of this Agreement with respect to any obligation hereunder, such Party shall take reasonable steps, consistent with Good Utility Practice, to remedy such breach. If either Party is unable to fulfill any obligation by reason of a Force Majeure Event, it shall give notice and the full particulars of the obligations affected by such Force Majeure Event to the other Party in writing or by telephone (if followed by written notice) as soon as reasonably practicable, but not later than fourteen (14) calendar days, after such Party becomes aware of the event. A failure to give timely notice of the Force Majeure event shall constitute a waiver of the claim of Force Majeure Event. The Party experiencing the Force Majeure Event shall also provide notice, as soon as reasonably practicable, when the Force Majeure Event ends.

(2) Notwithstanding the foregoing, a Force Majeure Event does not relieve a Party affected by a Force Majeure Event of its obligation to make payments or of any consequences of non-performance pursuant to the ERCOT Protocols or under this Agreement, except that the excuse from Default provided by subsection 8(A)(5) above is still effective.

D. Duty to Mitigate. Except as expressly provided otherwise herein, each Party shall use commercially reasonable efforts to mitigate any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Section 9. Limitation of Damages and Liability and Indemnification.

A. EXCEPT AS EXPRESSLY LIMITED IN THIS AGREEMENT OR THE ERCOT PROTOCOLS, ERCOT OR PARTICIPANT MAY SEEK FROM THE OTHER, THROUGH APPLICABLE DISPUTE RESOLUTION PROCEDURES SET FORTH IN THE ERCOT PROTOCOLS, ANY MONETARY DAMAGES OR OTHER REMEDY OTHERWISE ALLOWABLE UNDER TEXAS LAW, AS DAMAGES FOR DEFAULT OR BREACH OF THE OBLIGATIONS UNDER THIS AGREEMENT; PROVIDED, HOWEVER, THAT NEITHER PARTY IS LIABLE TO THE OTHER FOR ANY SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY THAT MAY OCCUR, IN WHOLE OR IN PART, AS A RESULT OF A DEFAULT UNDER THIS AGREEMENT, A TORT, OR ANY OTHER CAUSE, WHETHER OR NOT A PARTY HAD KNOWLEDGE OF THE CIRCUMSTANCES THAT RESULTED IN THE SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY, OR COULD HAVE FORESEEN THAT SUCH DAMAGES OR INJURY WOULD OCCUR.

B. With respect to any dispute regarding a Default or breach by ERCOT of its obligations under this Agreement, ERCOT expressly waives any Limitation of Liability to which it may be entitled under the Charitable Immunity and Liability Act of 1987, Tex. Civ. Prac. & Rem. Code §84.006, or successor statute.

C. The Parties have expressly agreed that, other than subsections A and B of this Section, this Agreement shall not include any other limitations of liability or indemnification provisions, and that such issues shall be governed solely by applicable law, in a manner consistent with the Choice of Law and Venue subsection of this Agreement, regardless of any contrary provisions that may be included in or subsequently added to the ERCOT Protocols (outside of this Agreement).

D. The Independent Market Monitor (IMM), and its directors, officers, employees, and agents, shall not be liable to any person or Entity for any act or omission, other than an act or omission constituting gross negligence or intentional misconduct, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual, direct, indirect, or consequential damages of any kind resulting from or attributable to any such act or omission of the IMM, as long as such act or omission arose from or is related to matters within the scope of the IMM's authority arising under or relating to PURA §39.1515 and PUC SUBST. R. 25.365, Independent Market Monitor.

Section 10. Dispute Resolution.

A. In the event of a dispute, including a dispute regarding a Default, under this Agreement, Parties to this Agreement shall first attempt resolution of the dispute using the applicable dispute resolution procedures set forth in the ERCOT Protocols.

B. In the event of a dispute, including a dispute regarding a Default, under this Agreement, each Party shall bear its own costs and fees, including, but not limited to attorneys' fees, court costs, and its share of any mediation or arbitration fees.

Section 11. Miscellaneous.

A. Choice of Law and Venue. Notwithstanding anything to the contrary in this Agreement, this Agreement shall be deemed entered into and performable solely in Texas and, with the exception of matters governed exclusively by federal law, shall be governed by and construed and interpreted in accordance with the laws of the State of Texas that apply to contracts executed in and performed entirely within the State of Texas, without reference to any rules of conflict of laws. Neither Party waives primary jurisdiction as a defense; provided that any court suits regarding this Agreement shall be brought in a state or federal court located within Travis County, Texas, and the Parties hereby waive any defense of forum non-conveniens, except defenses under Tex. Civ. Prac. & Rem. Code §15.002(b).

B. Assignment.

(1) Notwithstanding anything herein to the contrary, a Party shall not assign or otherwise transfer all or any of its rights or obligations under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld or delayed, except that a Party may assign or transfer its rights and obligations under this Agreement without the prior written consent of the other Party (if neither the assigning Party or the assignee is then in Default of any Agreement with ERCOT):

(a) Where any such assignment or transfer is to an Affiliate of the Party; or

(b) Where any such assignment or transfer is to a successor to or transferee of the direct or indirect ownership or operation of all or part of the Party, or its facilities; or

(c) For collateral security purposes to aid in providing financing for itself, provided that the assigning Party will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by either Party pursuant to this Section will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). If requested by the Party making any such collateral assignment to a Financing Person, the other Party shall execute and deliver a consent to such assignment containing customary provisions, including representations as to corporate authorization, enforceability of this Agreement and absence of known Defaults, notice of material breach pursuant to Section 8(A), notice of Default, and an opportunity for the Financing Person to cure a material breach pursuant to Section 8(A) prior to it becoming a Default.

(2) An assigning Party shall provide prompt written notice of the assignment to the other Party. Any attempted assignment that violates this Section is void and ineffective. Any assignment under this Agreement shall not relieve either Party of its obligations under this Agreement, nor shall either Party's obligations be enlarged, in whole or in part, by reason thereof.

C. No Third Party Beneficiary. Except with respect to the rights of the Financing Persons in Section 11(B), (a) nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, (b) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (c) this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to this Agreement or the services to be provided hereunder. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

D. No Waiver. Parties shall not be required to give notice to enforce strict adherence to all provisions of this Agreement. No breach or provision of this Agreement shall be deemed waived, modified or excused by a Party unless such waiver, modification or excuse is in writing and signed by an authorized officer of such Party. The failure by or delay of either Party in enforcing or exercising any of its rights under this Agreement shall (a) not be deemed a waiver, modification or excuse of such right or of any breach of the same or different provision of this Agreement, and (b) not prevent a subsequent enforcement or exercise of such right. Each Party shall be entitled to enforce the other Party's covenants and promises contained herein, notwithstanding the existence of any claim or cause of action against the enforcing Party under this Agreement or otherwise.

E. Headings. Titles and headings of paragraphs and sections within this Agreement are provided merely for convenience and shall not be used or relied upon in construing this Agreement or the Parties' intentions with respect thereto.

F. Severability. In the event that any of the provisions, or portions or applications thereof, of this Agreement is finally held to be unenforceable or invalid by any court of competent jurisdiction, that determination shall not affect the enforceability or validity of the remaining portions of this Agreement, and this Agreement shall continue in full force and effect as if it had been executed without the invalid provision; provided, however, if either Party determines, in its sole discretion, that there is a material change in this Agreement by reason thereof, the Parties shall promptly enter into negotiations to replace the unenforceable or invalid provision with a valid and enforceable provision. If the Parties are not able to reach an agreement as the result of such negotiations within fourteen (14) days, either Party shall have the right to terminate this Agreement on three (3) days written notice.

G. Entire Agreement. Any exhibits attached to this Agreement are incorporated into this

Agreement by reference and made a part of this Agreement as if repeated verbatim in this Agreement. This Agreement represents the Parties' final and mutual understanding with respect to its subject matter. It replaces and supersedes any prior agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by any Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement. An agreement, statement, or promise not contained in this Agreement is not valid or binding.

H. Amendment. The standard form of this Agreement may only be modified through the procedure for modifying ERCOT Protocols described in the ERCOT Protocols. Any changes to the terms of the standard form of this Agreement shall not take effect until a new Agreement is executed between the Parties.

I. ERCOT's Right to Audit Participant. Participant shall keep detailed records for a period of three years of all activities under this Agreement giving rise to any information, statement, charge, payment or computation delivered to ERCOT under the ERCOT Protocols. Such records shall be retained and shall be available for audit or examination by ERCOT as hereinafter provided. ERCOT has the right during Business Hours and upon reasonable written notice and for reasonable cause to examine the records of Participant as necessary to verify the accuracy of any such information, statement, charge, payment or computation made under this Agreement. If any such examination reveals any inaccuracy in any such information, statement, charge, payment or computation, the necessary adjustments in such information, statement, charge, payment, computation, or procedures used in supporting its ongoing accuracy will be promptly made.

J. Participant's Right to Audit ERCOT. Participant's right to data and audit of ERCOT shall be as described in the ERCOT Protocols and shall not exceed the rights described in the ERCOT Protocols.

K. Further Assurances. Each Party agrees that during the term of this Agreement it will take such actions, provide such documents, do such things and provide such further assurances as may reasonably be requested by the other Party to permit performance of this Agreement.

L. Conflicts. This Agreement is subject to applicable federal, state, and local laws, ordinances, rules, regulations, orders of any Governmental Authority and tariffs. Nothing in this Agreement may be construed as a waiver of any right to question or contest any federal, state and local law, ordinance, rule, regulation, order of any Governmental Authority, or tariff. In the event of a conflict between this Agreement and an applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff, the applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff shall prevail, provided that Participant shall give notice to ERCOT of any such conflict affecting Participant. In the event of a conflict between the ERCOT Protocols and this Agreement, the provisions expressly set forth in this Agreement shall control.

M. No Partnership. This Agreement may not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party has any right, power, or authority to enter any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

N. Construction. In this Agreement, the following rules of construction apply, unless expressly provided otherwise or unless the context clearly requires otherwise:

(1) The singular includes the plural, and the plural includes the singular.

(2) The present tense includes the future tense, and the future tense includes the present tense.

(3) Words importing any gender include the other gender.

(4) The word "shall" denotes a duty.

(5) The word "must" denotes a condition precedent or subsequent.

(6) The word "may" denotes a privilege or discretionary power.

(7) The phrase "may not" denotes a prohibition.

(8) References to statutes, tariffs, regulations or ERCOT Protocols include all provisions consolidating, amending, or replacing the statutes, tariffs, regulations or ERCOT Protocols referred to.

(9) References to "writing" include printing, typing, lithography, and other means of reproducing words in a tangible visible form.

(10) The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(11) Any reference to a day, week, month or year is to a calendar day, week, month or year unless otherwise indicated.

(12) References to articles, Sections (or subdivisions of Sections), exhibits, annexes or schedules are to this Agreement, unless expressly stated otherwise.

(13) Unless expressly stated otherwise, references to agreements, ERCOT Protocols and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent the amendments and other modifications are not prohibited by this Agreement.

(14) References to persons or entities include their respective successors and permitted assigns and, for governmental entities, entities succeeding to their respective

functions and capacities.

(15) References to time are to Central Prevailing Time.

O. Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.

Electric Reliability Council of Texas, Inc.:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Participant:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Market Participant Name: ____

Market Participant DUNS: ____

ERCOT Nodal Protocols

Section 22

Attachment B: Standard Form Reliability Must-Run Agreement

February 1, 2022

Standard Form Reliability Must-Run Agreement
Between
Insert Participant
and
Electric Reliability Council of Texas, Inc.

This Reliability Must-Run Agreement (“Agreement”), effective as of ___________ of _______________, ___________ (“Effective Date”), is entered into by and between Insert Participant, a [Insert State of Registration and Entity type] (“Participant”) and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation (“ERCOT”).

Recitals

WHEREAS:

A. Participant is a Resource Entity as defined in the ERCOT Protocols, and Participant intends to supply Reliability Must-Run Service;

B. ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region; and

C. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the “Parties”) hereby agree as follows:

Section 1. Unit-Specific Terms.

A. Start Date: _______________, 20_____.

B. Stop Date: _______________, 20_____.

C. RMR Unit:_________________________.

D. Description of RMR Unit [*including location, name of Resource, etc.]:* ____ ____.

E. RMR Unit Information

(1) RMR Contracted Capacity and Target Availability:

Month - Year	Capacity (MW)	Target Availability (%)
Jan		
Feb		
Mar		
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		

F. Delivery Point: ___________________________

G. Revenue Meter Location (Use Resource IDs): __________________________

H. Resource Category: __________

I. Fuel Adder ($/MMBtu): __________

J. Initial Standby Cost data for contract period:

a. Total budgeted cost without contributed capital expenditures ($): __________

b. Total budgeted contributed capital expenditures ($): __________

c. Total hours in contract period: __________

d. Initial Standby Cost ($/hour): [Total Cost (a) * (1 + Incentive Factor) + Total contributed capital expenditures (b)] / Total Hours (c): __________

Standby Payments may be recalculated from time to time as defined in Section 3.14.1.12, Calculation of the Initial Standby Cost.

K. Primary Purpose of Service:

☐ Reliability

☐ Capacity in accordance with Section 6.5.1.1, ERCOT Control Area Authority

L. Notice. All notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three days after being deposited in the U.S. mail, first-class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or Federal Express delivery. Either Party may change its address for such notices by delivering to the other Party a written notice referring specifically to this Agreement. Notices required under the ERCOT Protocols shall be in accordance with the applicable Section of the ERCOT Protocols.

If to ERCOT:

Electric Reliability Council of Texas, Inc.
8000 Metropolis Drive (Building E), Suite 100
Austin, Texas 78744
Tel No. (512) 225-7000

Attn: ERCOT Legal Department

If to Participant:

[Insert Participant Name]
[Insert Contact Person/Dept.]
[Insert Street Address]
[Insert City, State Zip]
[Insert Telephone]
[Insert Facsimile]

Section 2. Definitions.

A. Unless herein defined, all definitions and acronyms found in the ERCOT Protocols shall be incorporated by reference into this Agreement.

B. "ERCOT Protocols" shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and Settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. For the purposes of determining prices, payments, and other economic rights of the Parties, the ERCOT Protocols in effect on the Effective Date govern this Agreement. For the purposes of determining all other responsibilities and rights at a given time, the ERCOT Protocols, as amended in accordance with the change procedure(s) described in the ERCOT Protocols, in effect at the time of the performance or non-performance of an action, shall govern with respect to that action.

Section 3. Term and Termination.

A. Term.

(1) This Agreement is effective beginning on the Effective Date.

(2) The "Term" of this Agreement begins at 0000 on the Start Date and ends at 2400 on the Stop Date. ERCOT, at its sole discretion, may terminate this Agreement before the end of the Term by giving 90 days' advance written notice to the Participant.

(3) Any Term longer than one (1) year requires ERCOT Board approval.

B. Extension by ERCOT. ERCOT may, at its sole discretion, extend this Agreement for a period up to ninety (90) days, even if ERCOT has previously provided notice to Participant of future termination of the Agreement, by providing at least thirty (30) days advance written notice to Participant of the extension.

C. Termination by Participant. Participant may, at its option, immediately terminate this Agreement upon the failure of ERCOT to continue to be certified by the PUCT as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151.

D. Termination by Mutual Agreement. This Agreement may be terminated upon written agreement of both parties at a time specified by such agreement; provided that Participant may still recover Eligible Costs (Standby Costs) and Incentive Factor payments already accrued prior to termination pursuant to this section.

E. Effect of Termination and Survival of Terms. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.

Section 4. Representations, Warranties, and Covenants.

A. Participant represents, warrants, and covenants that:

(1) Participant is duly organized, validly existing, and in good standing under the laws of the jurisdiction under which it is organized, and is authorized to do business in Texas;

(2) Participant has full power and authority to enter into this Agreement and perform all of Participant's obligations, representations, warranties, and covenants under this Agreement;

(3) Participant's past, present, and future agreements or Participant's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which Participant is a party or by which its assets or properties are bound do not materially affect performance of Participant's obligations under this Agreement;

(4) The execution, delivery, and performance of this Agreement by Participant have been duly authorized by all requisite action of its governing body;

(5) Except as set out in an exhibit (if any) to this Agreement, ERCOT has not, within the 24 months preceding the Effective Date, terminated for Default any Prior Agreement with Participant, any company of which Participant is a successor in interest, or any Affiliate of Participant;

(6) If any Defaults are disclosed on any such exhibit mentioned in subsection 4(A)(5), either (a) ERCOT has been paid, before execution of this Agreement, all sums due to it in relation to such Prior Agreement, or (b) ERCOT, in its reasonable judgment, has determined that this Agreement is necessary for system reliability, and Participant has made alternate arrangements satisfactory to ERCOT for the resolution of the Default under the Prior Agreement;

(7) Participant has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(8) Participant is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(9) Participant is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt;

(10) Participant acknowledges that it has received and is familiar with the ERCOT Protocols; and

(11) Participant acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the Term of this Agreement. For purposes of this Section, “materially affecting performance” means resulting in a materially adverse effect on Participant’s performance of its obligations under this Agreement.

B. <u>ERCOT represents, warrants, and covenants that:</u>

(1) ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;

(2) ERCOT is duly organized, validly existing, and in good standing under the laws of Texas, and is authorized to do business in Texas;

(3) ERCOT has full power and authority to enter into this Agreement and perform all of ERCOT’s obligations, representations, warranties, and covenants under this Agreement;

(4) ERCOT’s past, present, and future agreements or ERCOT’s organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which ERCOT is a party or by which its assets or properties are bound do not materially affect performance of ERCOT’s obligations under this Agreement;

(5) The execution, delivery, and performance of this Agreement by ERCOT have been duly authorized by all requisite action of its governing body;

(6) ERCOT has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(7) ERCOT is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(8) ERCOT is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt; and

(9) ERCOT acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the Term of this Agreement. For purposes of this Section, "materially affecting performance," means resulting in a materially adverse effect on ERCOT's performance of its obligations under this Agreement.

<u>Section 5. Participant Obligations.</u>

A. Participant shall comply with, and be bound by, all ERCOT Protocols as they pertain to provision of Reliability Must-Run Service by a Resource Entity.

B. All budget and actual cost information submitted to ERCOT in accordance with the Protocols, including costs for work that is expected to be performed by an Affiliate of the Resource Entity, must include only those costs that are necessary and reflective of fair-market value.

C. Participant shall not take any action, without first providing written notice to ERCOT and reasonable time for ERCOT and Market Participants to respond, that would cause a Market Participant within the ERCOT Region that is not a "public utility" under the Federal Power Act or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission.

<u>Section 6. ERCOT Obligations.</u>

A. ERCOT shall comply with, and be bound by, all ERCOT Protocols.

B. ERCOT shall not take any action, without first providing written notice to Participant and reasonable time for Participant and other Market Participants to respond, that would cause Participant, if Participant is not a "public utility" under the Federal Power Act, or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission. If ERCOT receives any notice similar to that described in Section 5(B) from any Market Participant, ERCOT shall provide notice of same to Participant.

Section 7. Capacity Tests for RMR Units.

A. Capacity Tests.

(1) A "Capacity Test" is a one-hour performance test of the RMR Unit by Participant. The capacity as shown by a Capacity Test is called "Tested Capacity" and is determined by the applicable net meter readings during the Capacity Test.

(2) ERCOT may require that a Capacity Test be run at ERCOT's discretion at any time when the RMR Unit is on line, but ERCOT may not require more than four Capacity Tests in a contract Term. ERCOT must give Participant at least two (2) hours advance notice, after the RMR Unit is on line, of a Capacity Test required by ERCOT, unless Participant agrees to less than two (2) hours. Participant may perform as many Capacity Tests as it desires, but Participant may not perform a Capacity Test without the prior approval of ERCOT, which approval ERCOT may not unreasonably withhold or delay. The Parties will reasonably cooperate to coordinate a Capacity Test. ERCOT has the right to reasonable advance notice of, and to have personnel present during, a Capacity Test.

B. Test Report. ERCOT shall give the Capacity Test results in writing (the "Capacity Test Report") to Participant within twenty-four (24) hours after the test is run.

C. Effect of Test.

(1) A determination of Tested Capacity is effective as of the beginning of the hour in which the Capacity Test is started. For all hours in which Tested Capacity is less than the RMR Capacity specified in Section 1(E)(1) above, then the Incentive Factor Percentage may be reduced as specified in the ERCOT Protocols applicable to RMR Service in effect on the Effective Date.

Section 8. Operation.

A. RMR Unit Maintenance. Before the start of each contract Term, Participant shall furnish ERCOT with its proposed schedule for Planned Outages for inspection, repair, maintenance, and overhaul of the RMR Unit for the contract Term. Participant will promptly advise ERCOT of any later changes to the schedule or estimated cost. The specific times for Planned Outages of the RMR Unit must be approved or rejected by ERCOT within thirty (30) days after submission by a Participant. Requested outages may be rejected only if necessary to assure reliability of the ERCOT System. ERCOT shall, if requested by Participant, endeavor to accommodate changes to the schedule to the extent that reliability of the ERCOT System is not materially affected by those changes. In all cases, ERCOT must find a time for Participant to perform maintenance in a reasonable timeframe.

B. Planning Data.

(1) Participant shall timely report to ERCOT those items and conditions necessary for ERCOT's internal planning and compliance with ERCOT's guidelines in

effect from time to time. The information supplied must include, without limitation, the following:

(a) Current Operating Plan (COP) for each hour of the next Operating Day submitted by 0600 in the Day-Ahead;

(b) Revised COP reflecting changes in the hourly availability of the RMR Unit as soon as reasonably practical, but in no event later than 60 minutes after the event that caused the change; and

(c) Status of the RMR Unit with respect to environmental limitations, if any. If any of the specified environmental limitations will be exceeded by ERCOT's planned or actual use of the RMR Unit Participant shall provide ERCOT with as much advance written notice as is reasonably possible.

(2) ERCOT and Participant shall timely coordinate with each other on the status of the RMR Unit with respect to Operational Limitations.

C. Delivery.

(1) ERCOT shall notify Participant, through a RUC instruction, of the hours, that the RMR Unit is to operate. ERCOT may not notify Participant to operate at levels above those stated in the COP.

(2) Participant shall produce and deliver electrical energy from the RMR Unit to the Delivery Point as dispatched by Security Constrained Economic Dispatch (SCED).

Section 9. Payment.

A. Payments for an RMR Unit. ERCOT shall pay Participant for the RMR Service provided under this Agreement as specified in the ERCOT Protocols applicable to RMR Service, as those ERCOT Protocols are in effect on the Effective Date.

B. Unexcused Misconduct Events.

(1) For an RMR Unit, a "Misconduct Event" means any hour or hours during which Participant is shown available in the COP, but fails to come On-Line for the hour or hours being RUC committed. Contiguous RUC deployments shall represent a single event in determining a "Misconduct Event".

(2) Each day that a Misconduct Event continues after Participant receives written notice from ERCOT of the Misconduct Event is a separate Misconduct Event. Misconduct Events are measured on a daily basis.

(3) Participant is excused from the RMR Charge for Unexcused Misconduct for any Misconduct Event that is (a) not due to intentionally incomplete, inaccurate, or dishonest reporting to ERCOT by Participant of the availability of the Unit, or (b) caused by a failure of the ERCOT Transmission Grid.

(4) If a Misconduct Event is not excused, then to reflect this lower-than-expected quality of firmness, the Participant is subject to the RMR Charge for Unexcused Misconduct as specified in the ERCOT Protocols in effect on the Effective Date.

(5) ERCOT shall inform Participant in writing of its determination if a Misconduct Event is unexcused.

(6) ERCOT may offset any amounts due by Participant to ERCOT under this Section against any amounts due by ERCOT to Participant under this Agreement.

Section 10. Default.

A. Event of Default.

(1) Failure by Participant to (i) pay when due, any payment or Financial Security obligation owed to ERCOT or its designee, if applicable, under any agreement with ERCOT ("Payment Breach"), or (ii) designate/maintain an association with a QSE (if required by the ERCOT Protocols) ("QSE Affiliation Breach"), shall constitute a material breach and event of default ("Default") unless cured within one (1) Bank Business Day after ERCOT delivers written notice of the breach to Participant. Provided further that if such a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a rolling 12-month period, the fourth such breach shall constitute a Default.

(2) A material breach other than a Payment Breach or a QSE Affiliation Breach includes any material failure by Participant to comply with the ERCOT Protocols. A material breach under this subsection shall constitute an event of Default by Participant unless cured within fourteen (14) Business Days after delivery by ERCOT of written notice of the material breach to Participant.

Participant must begin work or other efforts within three (3) Business Days to cure such material breach after delivery of the breach notice by ERCOT, and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a 12-month period, the fourth such breach shall constitute a Default.

A material breach under this subsection shall not result in a Default if the breach cannot reasonably be cured within fourteen (14) Business Days, and Participant:

(a) Promptly provides ERCOT with written notice of the reasons why the breach cannot reasonably be cured within fourteen (14) Business Days;

(b) Begins to work or other efforts to cure the breach within three (3) Business Days after ERCOT's delivery of the notice to Participant; and

(c) Prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(3) The occurrence and continuation of any of the following events shall constitute an automatic Default by Participant:

(a) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within 90 days thereafter;

(b) The RMR Unit's operation is abandoned without intent to return it to operation during the Term;

(c) At any time, the Actual Availability is equal to or less than 50% of the Target Availability as specified in Table 1 Section 1 (E)(1) of this Agreement; or

(d) Three or more unexcused Misconduct Events occur during a contract Term.

(4) Except as otherwise herein, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a Payment Breach, shall constitute a Default by ERCOT unless cured within fourteen (14) Business Days after delivery by Participant of written notice of the material breach to ERCOT. ERCOT must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by Participant of written notice of such material breach by ERCOT and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a 12-month period, the fourth such breach shall constitute a Default.

(5) If, due to a Force Majeure Event, a Party is in breach with respect to any obligation hereunder, such breach shall not result in a Default by that Party.

B. <u>Remedies for Default.</u>

(1) <u>ERCOT's Remedies for Default</u>. In the event of a Default by Participant, ERCOT may pursue any remedies ERCOT has under this Agreement, at law, or in equity, subject to the provisions of Section 12: Dispute Resolution of this Agreement. In the event of a Default by Participant, if the ERCOT Protocols do not specify a remedy for a particular Default, ERCOT may, at its option, upon written notice to Participant, immediately terminate this Agreement, with termination to be effective upon the date of delivery of notice. In the event of Participant's bankruptcy, Participant waives any right to challenge ERCOT's right to set off amounts ERCOT owes to Participant by the amount of any sums owed by Participant to ERCOT, including any amounts owed pursuant to the operation of the Protocols.

(2) <u>Participant's Remedies for Default.</u>

(a) Unless otherwise specified in this Agreement or in the ERCOT Protocols, and subject to the provisions of Section 12: Dispute Resolution of this Agreement, in the event of a Default by ERCOT, Participant's remedies shall be limited to:

(i) Immediate termination of this Agreement upon written notice to ERCOT;

(ii) Monetary recovery in accordance with the Settlement procedures set forth in the ERCOT Protocols; and

(iii) Specific performance.

(b) However, in the event of a material breach by ERCOT of any of its representations, warranties or covenants, described in Section 4(B), Participant's sole remedy shall be immediate termination of this Agreement upon written notice to ERCOT.

(3) A Default or breach of this Agreement by a Party shall not relieve either Party of the obligation to comply with the ERCOT Protocols.

C. Force Majeure.

(1) If, due to a Force Majeure Event, either Party is in breach of this Agreement with respect to any obligation hereunder, such Party shall take reasonable steps, consistent with Good Utility Practice, to remedy such breach. If either Party is unable to fulfill any obligation by reason of a Force Majeure Event, it shall give notice and the full particulars of the obligations affected by such Force Majeure Event to the other Party in writing or by telephone (if followed by written notice) as soon as reasonably practicable, but not later than fourteen (14) calendar days, after such Party becomes aware of the event. A failure to give timely notice of the Force Majeure Event shall constitute a waiver of the claim of Force Majeure Event. The Party experiencing the Force Majeure Event shall also provide notice, as soon as reasonably practicable, when the Force Majeure Event ends.

(2) Notwithstanding the foregoing, a Force Majeure Event does not relieve a Party affected by a Force Majeure Event of its obligation to make payments or of any consequences of non-performance pursuant to the ERCOT Protocols or under this Agreement, except that the excuse from Default provided by subsection 10(A)(5) above is still effective.

D. Duty to Mitigate. Except as expressly provided otherwise herein, each Party shall use commercially reasonable efforts to mitigate any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Section 11. Limitation of Damages and Liability and Indemnification.

A. EXCEPT AS EXPRESSLY LIMITED IN THIS AGREEMENT OR THE ERCOT PROTOCOLS, ERCOT OR PARTICIPANT MAY SEEK FROM THE OTHER, THROUGH APPLICABLE DISPUTE RESOLUTION PROCEDURES SET FORTH

IN THE ERCOT PROTOCOLS, ANY MONETARY DAMAGES OR OTHER REMEDY OTHERWISE ALLOWABLE UNDER TEXAS LAW, AS DAMAGES FOR DEFAULT OR BREACH OF THE OBLIGATIONS UNDER THIS AGREEMENT; PROVIDED, HOWEVER, THAT NEITHER PARTY IS LIABLE TO THE OTHER FOR ANY SPECIAL, INDIRECT, PUNITIVE, OR CONSEQUENTIAL DAMAGES OR INJURY THAT MAY OCCUR, IN WHOLE OR IN PART, AS A RESULT OF A DEFAULT UNDER THIS AGREEMENT, A TORT, OR ANY OTHER CAUSE, WHETHER OR NOT A PARTY HAD KNOWLEDGE OF THE CIRCUMSTANCES THAT RESULTED IN THE SPECIAL, INDIRECT, PUNITIVE, OR CONSEQUENTIAL DAMAGES OR INJURY, OR COULD HAVE FORESEEN THAT SUCH DAMAGES OR INJURY WOULD OCCUR.

B. With respect to any dispute regarding a Default or breach by ERCOT of its obligations under this Agreement, ERCOT expressly waives any Limitation of Liability to which it may be entitled under the Charitable Immunity and Liability Act of 1987, Tex. Civ. Prac. & Rem. Code §84.006, or successor statute.

C. The Parties have expressly agreed that, other than subsections (A) and (B) of this Section, this Agreement shall not include any other limitations of liability or indemnification provisions, and that such issues shall be governed solely by applicable law, in a manner consistent with the Choice of Law and Venue subsection of this Agreement, regardless of any contrary provisions that may be included in or subsequently added to the ERCOT Protocols (outside of this Agreement).

Section 12. Dispute Resolution.

A. In the event of a dispute, including a dispute regarding a Default, under this Agreement, Parties to this Agreement shall first attempt resolution of the dispute using the applicable dispute resolution procedures set forth in the ERCOT Protocols.

B. In the event of a dispute, including a dispute regarding a Default, under this Agreement, each Party shall bear its own costs and fees, including, but not limited to attorneys' fees, court costs, and its share of any mediation or arbitration fees.

Section 13. Miscellaneous.

A. Choice of Law and Venue. Notwithstanding anything to the contrary in this Agreement, this Agreement shall be deemed entered into and performable solely in Texas and, with the exception of matters governed exclusively by federal law, shall be governed by and construed and interpreted in accordance with the laws of the State of Texas that apply to contracts executed in and performed entirely within the State of Texas, without reference to any rules of conflict of laws. Neither Party waives primary jurisdiction as a defense; provided that any court suits regarding this Agreement shall be brought in a state or federal court located within Travis County, Texas, and the Parties hereby waive any defense of *forum non-conveniens*, except defenses under Tex. Civ. Prac. & Rem. Code §15.002(b).

B. Assignment.

(1) Notwithstanding anything herein to the contrary, a Party shall not assign or otherwise transfer all or any of its rights or obligations under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld or delayed, except that a Party may assign or transfer its rights and obligations under this Agreement without the prior written consent of the other Party (if neither the assigning Party or the assignee is then in Default of any Agreement with ERCOT):

(a) Where any such assignment or transfer is to an Affiliate of the Party; or

(b) Where any such assignment or transfer is to a successor to or transferee of the direct or indirect ownership or operation of all or part of the Party, or its Facilities; or

(c) For collateral security purposes to aid in providing financing for itself, provided that the assigning Party will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by either Party pursuant to this Section will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). If requested by the Party making any such collateral assignment to a Financing Person, the other Party shall execute and deliver a consent to such assignment containing customary provisions, including representations as to corporate authorization, enforceability of this Agreement and absence of known Defaults, notice of material breach pursuant to Section 10(A), and an opportunity for the Financing Person to cure a material breach pursuant to Section 10(A) prior to it becoming a Default.

(2) An assigning Party shall provide prompt written notice of the assignment to the other Party. Any attempted assignment that violates this Section is void and ineffective. Any assignment under this Agreement shall not relieve either Party of its obligations under this Agreement, nor shall either Party's obligations be enlarged, in whole or in part, by reason thereof.

C. No Third Party Beneficiary. Except with respect to the rights of the Financing Persons in Section 13(B)(1), (a) nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, (b) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (c) this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to this Agreement or the services to be provided hereunder. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

D. No Waiver. Parties shall not be required to give notice to enforce strict adherence to all provisions of this Agreement. No breach or provision of this Agreement shall be deemed waived, modified or excused by a Party unless such waiver, modification or excuse is in writing and signed by an authorized officer of such Party. The failure by or delay of either Party in enforcing or exercising any of its rights under this Agreement shall (a) not be deemed a waiver, modification or excuse of such right or of any breach of the same or different provision of this Agreement, and (b) not prevent a subsequent enforcement or exercise of such right. Each Party shall be entitled to enforce the other Party's covenants and promises contained herein, notwithstanding the existence of any claim or cause of action against the enforcing Party under this Agreement or otherwise.

E. Headings. Titles and headings of paragraphs and sections within this Agreement are provided merely for convenience and shall not be used or relied upon in construing this Agreement or the Parties' intentions with respect thereto.

F. Severability. In the event that any of the provisions, or portions or applications thereof, of this Agreement is finally held to be unenforceable or invalid by any court of competent jurisdiction, that determination shall not affect the enforceability or validity of the remaining portions of this Agreement, and this Agreement shall continue in full force and effect as if it had been executed without the invalid provision; provided, however, if either Party determines, in its sole discretion, that there is a material change in this Agreement by reason thereof, the Parties shall promptly enter into negotiations to replace the unenforceable or invalid provision with a valid and enforceable provision. If the Parties are not able to reach an agreement as the result of such negotiations within fourteen (14) days, either Party shall have the right to terminate this Agreement on three (3) days written notice.

G. Entire Agreement. Any exhibits attached to this Agreement are incorporated into this Agreement by reference and made a part of this Agreement as if repeated verbatim in this Agreement. This Agreement represents the Parties' final and mutual understanding with respect to its subject matter. It replaces and supersedes any Prior Agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by any Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement. An agreement, statement, or promise not contained in this Agreement is not valid or binding.

H. Amendment. The standard form of this Agreement may only be modified through the procedure for modifying ERCOT Protocols described in the ERCOT Protocols. Any changes to the terms of the standard form of this Agreement shall not take effect until a new Agreement is executed between the Parties.

I. ERCOT's Right to Audit Participant. Participant shall keep detailed records for a period of three years of all activities under this Agreement giving rise to any information, statement, charge, payment, or computation delivered to ERCOT under the ERCOT Protocols. Such records shall be retained and shall be available for audit or examination by ERCOT as hereinafter provided. ERCOT has the right during Business Hours and upon reasonable written notice and for reasonable cause to examine the records of

Participant as necessary to verify the accuracy of any such information, statement, charge, payment, or computation made under this Agreement. If any such examination reveals any inaccuracy in any such information, statement, charge, payment or computation, the necessary adjustments in such information, statement, charge, payment, computation, or procedures used in supporting its ongoing accuracy will be promptly made.

J. Participant's Right to Audit ERCOT. Participant's right to data and audit of ERCOT shall be as described in the ERCOT Protocols and shall not exceed the rights described in the ERCOT Protocols.

K. Further Assurances. Each Party agrees that during the Term of this Agreement it will take such actions, provide such documents, do such things, and provide such further assurances as may reasonably be requested by the other Party to permit performance of this Agreement.

L. Conflicts. This Agreement is subject to applicable federal, state, and local laws, ordinances, rules, regulations, orders of any Governmental Authority, and tariffs. Nothing in this Agreement may be construed as a waiver of any right to question or contest any federal, state and local law, ordinance, rule, regulation, order of any Governmental Authority, or tariff. In the event of a conflict between this Agreement and an applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff, the applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff shall prevail, provided that Participant shall give notice to ERCOT of any such conflict affecting Participant. In the event of a conflict between the ERCOT Protocols and this Agreement, the provisions expressly set forth in this Agreement shall control.

M. No Partnership. This Agreement may not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party has any right, power, or authority to enter any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

N. Construction. In this Agreement, the following rules of construction apply, unless expressly provided otherwise or unless the context clearly requires otherwise:

(1) The singular includes the plural, and the plural includes the singular.

(2) The present tense includes the future tense, and the future tense includes the present tense.

(3) Words importing any gender include the other gender.

(4) The word "shall" denotes a duty.

(5) The word "must" denotes a condition precedent or subsequent.

(6) The word "may" denotes a privilege or discretionary power.

(7) The phrase "may not" denotes a prohibition.

(8) References to statutes, tariffs, regulations or ERCOT Protocols include all provisions consolidating, amending, or replacing the statutes, tariffs, regulations or ERCOT Protocols referred to.

(9) References to "writing" include printing, typing, lithography, and other means of reproducing words in a tangible visible form.

(10) The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(11) Any reference to a day, week, month or year is to a calendar day, week, month, or year unless otherwise indicated.

(12) References to articles, Sections (or subdivisions of Sections), exhibits, annexes, or schedules are to this Agreement, unless expressly stated otherwise.

(13) Unless expressly stated otherwise, references to agreements, ERCOT Protocols and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent the amendments and other modifications are not prohibited by this Agreement.

(14) References to persons or entities include their respective successors and permitted assigns and, for governmental entities, entities succeeding to their respective functions and capacities.

(15) References to time are to Central Prevailing Time.

O. Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED, AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.

Electric Reliability Council of Texas, Inc.:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Participant:

By: ______________________________

Name:

Title:

Date:

Market Participant Name:

Market Participant DUNS:

ERCOT Nodal Protocols

Section 22

Attachment C: Amendment to Standard Form Market Participant Agreement

April 1, 2022

Amendment to
Standard Form Market Participant Agreement
Between
[Insert Participant]
and
Electric Reliability Council of Texas, Inc.

This AMENDMENT to the Standard Form Market Participant Agreement (“Amendment”), effective as of the ___________ day of ____________________, ___________ (“Effective Date”), is entered into by and between [Insert Participant], a [Insert State of Registration and Entity Type] (“Participant”) and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation (“ERCOT”).

Recitals

WHEREAS, Participant and ERCOT entered into a Standard Form Market Participant Agreement (SFA) dated ; and

WHEREAS, Participant and ERCOT wish to amend that SFA to include Market Participant registrations designated below.

NOW, THEREFORE, Participant and ERCOT agree that paragraph A in the “Recitals” section of that SFA shall be deleted in its entirety and replaced with the following:

A. As defined in the ERCOT Protocols, Participant is a (check all that apply):

☐ Load Serving Entity (LSE)

☐ Qualified Scheduling Entity (QSE)

☐ Transmission Service Provider (TSP)

☐ Distribution Service Provider (DSP)

☐ Congestion Revenue Right (CRR) Account Holder

☐ Resource Entity

☐ Renewable Energy Credit (REC) Account Holder

This Amendment modifies the existing SFA only to include those Market Participant registrations designated above by Participant.

This Amendment in no way alters the terms and conditions of the existing SFA other than as specifically set forth herein.

SIGNED, ACCEPTED AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Amendment to the Standard Form Market Participant Agreement.

Electric Reliability Council of Texas, Inc.:

By: ____

Name: ____

Title: ____

Date: _____________________________

Participant:

By: ____

Name:

Title:

Date:

Market Participant Name:

Market Participant DUNS:

[NPRR857: Replace Section 22 Attachment C above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

Amendment to
Standard Form Market Participant Agreement
Between
[Participant]
and
Electric Reliability Council of Texas, Inc.

This AMENDMENT to the Standard Form Market Participant Agreement ("Amendment"), effective as of the ___________ day of ____________________, ___________ ("Effective Date"), is entered into by and between [Participant], a [State of Registration and Entity Type] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS, Participant and ERCOT entered into a Standard Form Market Participant Agreement (SFA) dated ______________; and

WHEREAS, Participant and ERCOT wish to amend that SFA to include Market Participant registrations designated below.

NOW, THEREFORE, Participant and ERCOT agree that paragraph A in the "Recitals" section of that SFA shall be deleted in its entirety and replaced with the following:

A. As defined in the ERCOT Protocols, Participant is a (check all that apply):

☐ Load Serving Entity (LSE)

☐ Qualified Scheduling Entity (QSE)

☐ Transmission Service Provider (TSP)

☐ Distribution Service Provider (DSP)

☐ Congestion Revenue Right (CRR) Account Holder

☐ Resource Entity

☐ Renewable Energy Credit (REC) Account Holder

☐ Direct Current Tie Operator (DCTO)

This Amendment modifies the existing SFA only to include those Market Participant registrations designated above by Participant.

This Amendment in no way alters the terms and conditions of the existing SFA other than as specifically set forth herein.

SIGNED, ACCEPTED AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Amendment to the Standard Form Market Participant Agreement.

Electric Reliability Council of Texas, Inc.:

By: ____

Name: ______________________________________

Title: ______________________________________

Date: __________________________

Participant:

By: ____

Name: ______________________________________

Title: ______________________________________

Date:_______________________________________

Market Participant Name: ____

Market Participant DUNS: ____

ERCOT Nodal Protocols

Section 22

Attachment D: Standard Form Black Start Agreement

February 1, 2022

Standard Form Black Start Agreement
Between
Insert Participant
and
Electric Reliability Council of Texas, Inc.

This Black Start Agreement ("Agreement"), effective as of _________ of _____________, ___________ ("Effective Date"), is entered into by and between Insert Participant, a [Insert State of Registration and Entity type] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS:

A. Participant is a Resource Entity as defined in the ERCOT Protocols, and Participant intends to provide Black Start Service (BSS);

B. ERCOT is the Independent Organization certified under the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2007) (PURA) for the ERCOT Region; and

C. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the "Parties") hereby agree as follows:

Section 1. Resource-Specific Terms.

A. Start Date: ____________________.

B. Black Start Resource.

(1) Description of Black Start Resource [including location, number of generators, metering scheme, etc.]:

____
____, as described in more detail on Exhibit 1.

(2) Nameplate Capacity in MW: _____

(3) Delivery Point: ____________________________

(4) Revenue Meter Location (use Resource IDs): __________________________

C. Price:

Hourly Standby Price: $________ per hour

D. Notice. All notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three days after being deposited in the U.S. mail, first class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or Federal Express delivery. Either Party may change its address for such notices by delivering to the other Party a written notice referring specifically to this Agreement. Notices required under the ERCOT Protocols shall be in accordance with the applicable Section of the ERCOT Protocols.

If to ERCOT:

Electric Reliability Council of Texas, Inc.
8000 Metropolis Drive (Building E), Suite 100
Austin, Texas 78744
Tel No. (512) 225-7000

If to Participant:

[Insert Participant Name]
[Insert Contact Person/Dept.]
[Insert Street Address]
[Insert City, State Zip]
[Insert Telephone]
[Insert Facsimile]

Section 2. Definitions.

A. Unless herein defined, all definitions and acronyms found in the ERCOT Protocols shall be incorporated by reference into this Agreement.

B. "ERCOT Protocols" shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and Settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. For the purposes of determining responsibilities and rights at a given time, the ERCOT Protocols, as amended in accordance with the change procedure(s) described in the ERCOT Protocols, in effect at the time of the performance or non-performance of an action, shall govern with respect to that action.

Section 3. Term and Termination.

A. Term.

(1) This Agreement is effective beginning on the Effective Date.

(2) The full term ("Full Term") of this Agreement begins on the Start Date and continues for a period of two years.

B. Termination by Participant. Participant may, at its option, terminate this Agreement immediately upon the failure of ERCOT to continue to be certified by the Public Utility Commission of Texas (PUCT) as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151.

C. Effect of Termination and Survival of Terms. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.

Section 4. Representations, Warranties, and Covenants.

A. Participant represents, warrants, and covenants that:

(1) Participant is duly organized, validly existing, and in good standing under the laws of the jurisdiction under which it is organized, and is authorized to do business in Texas;

(2) Participant has full power and authority to enter into this Agreement and perform all of Participant's obligations, representations, warranties, and covenants under this Agreement;

(3) Participant's past, present, and future agreements or Participant's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which Participant is a party or by which its assets or properties are bound do not materially affect performance of Participant's obligations under this Agreement;

(4) The execution, delivery, and performance of this Agreement by Participant have been duly authorized by all requisite action of its governing body;

(5) Except as set out in an exhibit (if any) to this Agreement, ERCOT has not, within the 24 months preceding the Effective Date, terminated for Default any Prior Agreement with Participant, any company of which Participant is a successor in interest, or any Affiliate of Participant;

(6) If any Defaults are disclosed on any such exhibit mentioned in subsection 4(A)(5), either (a) ERCOT has been paid, before execution of this Agreement, all sums due to it in relation to such Prior Agreement, or (b) ERCOT, in its reasonable judgment, has determined that this Agreement is necessary for system

reliability, and Participant has made alternate arrangements satisfactory to ERCOT for the resolution of the Default under the Prior Agreement;

(7) Participant has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits, and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(8) Participant is not in violation of any laws, ordinances, or governmental rules, regulations, or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(9) Participant is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt;

(10) Participant acknowledges that it has received and is familiar with the ERCOT Protocols; and

(11) Participant acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, “materially affecting performance” means resulting in a materially adverse effect on Participant’s performance of its obligations under this Agreement.

B. <u>ERCOT represents, warrants, and covenants that</u>:

(1) ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;

(2) ERCOT is duly organized, validly existing, and in good standing under the laws of Texas, and is authorized to do business in Texas;

(3) ERCOT has full power and authority to enter into this Agreement and perform all of ERCOT’s obligations, representations, warranties and covenants under this Agreement;

(4) ERCOT’s past, present and future agreements or ERCOT’s organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which ERCOT is a party or by which its assets or properties are bound do not materially affect performance of ERCOT’s obligations under this Agreement;

(5) The execution, delivery, and performance of this Agreement by ERCOT have been duly authorized by all requisite action of its governing body;

(6) ERCOT has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(7) ERCOT is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(8) ERCOT is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt; and

(9) ERCOT acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, “materially affecting performance” means resulting in a materially adverse effect on ERCOT’s performance of its obligations under this Agreement.

Section 5. Participant Obligations.

A. Participant shall comply with, and be bound by, all ERCOT Protocols, ERCOT Operating Guides, and the North American Electric Reliability Corporation (NERC) Reliability Standards as they pertain to operation of a Black Start Resource by a Resource Entity.

B. Participant shall not take any action, without first providing written notice to ERCOT and reasonable time for ERCOT and Market Participants to respond, that would cause a Market Participant within the ERCOT Region that is not a “public utility” under the Federal Power Act, 16 U.S.C. § 824(e)(2005), or ERCOT itself to become a “public utility” under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission (FERC).

Section 6. ERCOT Obligations.

A. ERCOT shall comply with, and be bound by, all ERCOT Protocols.

B. ERCOT shall not take any action, without first providing written notice to Participant and reasonable time for Participant and other Market Participants to respond, that would cause Participant if Participant is not a “public utility” under the Federal Power Act, or ERCOT itself to become a “public utility” under the Federal Power Act or become subject to the plenary jurisdiction of the FERC. If ERCOT receives any notice similar to that described in Section 5(B) from any Market Participant, ERCOT shall provide notice of same to Participant.

Section 7. Black Start Decertification.

If a Black Start Resource does not remain certified, or if it is in default as described in Section 10(A)(2)(e) during the term of this Agreement, then the Hourly Standby Fee is reduced to zero for the remainder of the Full Term, and Participant will be required to refund to ERCOT certain amounts paid by ERCOT under this Agreement during the Full Term as described in the ERCOT Protocols.

Section 8. Operation.

A. Black Start Resource Maintenance. Before the start of the contract year, Participant shall furnish ERCOT with its proposed schedule for Planned Outages for inspection, repair, maintenance, and overhaul of the Black Start Resource for the contract year. Participant will promptly advise ERCOT of any later changes to the schedule. The specific times for Planned Outages of the Black Start Resource must be approved by ERCOT. Such approval may be withheld if necessary to assure reliability of the ERCOT System. ERCOT shall, if requested by Participant, endeavor to accommodate changes to the schedule to the extent that reliability of the ERCOT System is not materially affected by those changes. In all cases, ERCOT must find a time for Participant to perform maintenance in a reasonable timeframe as defined by Good Utility Practice.

B. Planning Data.

Participant shall timely report to ERCOT those items and conditions necessary for ERCOT's internal planning and compliance with ERCOT's guidelines in effect from time to time. The information supplied must include, without limitation, the following:

(1) Availability Plan for each hour of the next Operating Day submitted by 0600 of the preceding day; and

(2) Revised Availability Plan reflecting changes in hourly availability of Black Start Capacity status as indicated in a revised Availability Plan as soon as reasonably practical, but in no event later than 60 minutes after the event that caused the change.

C. Testing.

Participant shall perform quarterly Black Start Resource Availability Tests as described in these Protocols.

D. Delivery.

(1) ERCOT will make every effort to notify the Participant, through its Qualified Scheduling Entity (QSE) or Transmission Service Provider (TSP), when the Black Start Resource must black start. It is, however the responsibility of the Participant to initiate the start-up process of Black Start Resources in preparation for system restoration.

(2) If the ERCOT Transmission Grid at the Black Start Resource becomes deenergized and if Participant cannot communicate with either ERCOT or the

Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) serving the Black Start Resource, then Participant shall follow the procedures specified for the Black Start Resource under ERCOT's Black Start plan in the Operating Guides, but Participant shall not commence delivering electric energy into the ERCOT System without specific instructions to do so from either ERCOT or the TSP and/or DSP serving the Black Start Resource.

Section 9. Payment.

A. Hourly Standby Fee Payments. ERCOT shall pay Participant the Hourly Standby Fee as described below, except as specified otherwise in Section 7 above.

(1) Availability

(a) "Available" means, with respect to a given hour, that Participant has declared, in its Availability Plan, that the Black Start Resource is able to start without a connection to the ERCOT Transmission Grid.

(b) The Black Start Resource is not Available if:

(i) The Black Start Resource utilizes a power pool outside of ERCOT to start and the transmission path(s) between the Resource and the other power pool is not available due to an outage; or

(ii) The Black Start Resource utilizes a power pool outside of ERCOT to start but fails to maintain a firm standby supply contract for that power pool; or

(iii) The Black Start Resource has failed a Black Start Resource Availability Test, as described in the ERCOT Protocols or Operating Guides and has not passed a subsequent Black Start Resource Availability Test; or

(iv) The Black Start Resource has failed to start when required under this Agreement, and has not passed a subsequent Black Start Resource Availability Test; or

(v) The Black Start Resource failed to perform when issued a Dispatch Instruction to come On-Line any time other than for BSS and has not passed a subsequent Black Start Resource Availability Test.

(c) ERCOT shall use the Black Start Resource's Availability Plan as the source of Black Start Resource availability information.

(2) "Black Start Service Hourly Rolling Equivalent Availability Factor (BSSHREAF)" means, with respect to a given hour, the quotient (expressed as a percentage) of (a) the number of hours, including the given hour and the immediately preceding 4,379 hours, in which the Black Start Resource was

Available, divided by (b) 4,380; provided that, to the extent that 4,379 hours have not elapsed since the Start Date (the difference between 4,379 and the hours that have elapsed being referred to herein as the "Assumed Hours"), the Black Start Resource shall be deemed, for purposes of this calculation, to be Available for the Assumed Hour unless the Black Start Resource has failed to perform in response to a blackout event or when a Dispatch Instruction to come On-Line has been issued. Participant's failure to perform shall be subject to possible claw-back of its Hourly Standby Fee and reduced payment during the Assumed Hours period. A Force Majeure Event is treated the same as any other cause for unavailability for the purposes of calculating BSSHREAF.

(3) "Hourly Standby Fee" means, with respect to a given hour, the result determined from the following table:

Black Start Service Hourly Rolling Availability Factor (BSSHREAF)	Hourly Standby Fee
If BSSHREAF is more than or equal to 85%	Hourly Standby Price ($)
If BSSHREAF is less than 85% but more than 35%	Hourly Standby Price * [100%-(85%-BSSHREAF) * 2] ($)
If BSSHREAF is equal to or less than 35%	Zero

Section 10. Default.

A. Event of Default.

(1) Failure by Participant to (i) pay when due, any payment or Financial Security obligation owed to ERCOT or its designee, if applicable, under any agreement with ERCOT ("Payment Breach"), or (ii) designate/maintain an association with a QSE (if required by the ERCOT Protocols) ("QSE Affiliation Breach"), shall constitute a material breach and event of default ("Default") unless cured within one (1) Business Day after ERCOT delivers written notice of the breach to Participant. Provided further that if such a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three times within a rolling 12-month period, the fourth such breach shall constitute a Default.

(2) A material breach other than a Payment Breach or a QSE Affiliation Breach includes any material failure by Participant to comply with the ERCOT Protocols. A material breach under this subsection shall constitute an event of Default by Participant unless cured within fourteen (14) Business Days after delivery by ERCOT of written notice of the material breach to Participant.

Participant must begin work or other efforts within three (3) Business Days to cure such material breach after delivery of the breach notice by ERCOT, and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a 12-month period, the fourth such breach shall constitute a Default.

A material breach under this subsection shall not result in a Default if the breach cannot reasonably be cured within fourteen (14) Business Days, and Participant:

(a) Promptly provides ERCOT with written notice of the reasons why the breach cannot reasonably be cured within fourteen (14) Business Days;

(b) Begins to work or other efforts to cure the breach within three (3) Business Days after ERCOT's delivery of the notice to Participant; and

(c) Prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(3) The occurrence and continuation of any of the following events shall constitute an automatic Default by Participant:

(a) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceeding, that is dismissed within 90 days thereafter;

(b) The Black Start Resource's operation is abandoned without an intent to return it to operation during the Full Term;

(c) At any time, the Black Start Service Hourly Rolling Equivalent Availability Factor (BSSHREAF) is equal to or less than 50%; or

(d) An Available Black Start Resource fails to perform successfully as required during a Partial Blackout or Blackout.

(4) Except as otherwise excused herein, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a Payment Breach, shall constitute a Default by ERCOT unless cured within fourteen (14) Business Days after delivery by Participant of written notice of the material breach to ERCOT. ERCOT must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by Participant of written notice of such material breach by ERCOT and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach,

occurs more than three (3) times within a 12-month period, the fourth such breach shall constitute a Default.

(5) If, due to a Force Majeure Event, a Party is in breach with respect to any obligation hereunder, such breach shall not result in a Default by that Party.

(6) Notwithstanding anything to the contrary, if Participant uses a Switchable Generation Resource (SWGR) as the Black Start Resource, the requirements or instructions of another Control Area Operator shall not constitute a Force Majeure Event or otherwise excuse the Participant from providing BSS or performing its obligations under this Agreement.

B. Remedies for Default.

(1) ERCOT's Remedies for Default. In the event of a Default by Participant, ERCOT may pursue any remedies ERCOT has under this Agreement, at law, or in equity, subject to the provisions of Section 12, Dispute Resolution, of this Agreement. In the event of a Default by Participant, if the ERCOT Protocols do not specify a remedy for a particular Default, ERCOT may, at its option, upon written notice to Participant, immediately terminate this Agreement, with termination to be effective upon the date of delivery of notice. In the event of Participant's bankruptcy, Participant waives any right to challenge ERCOT's right to set-off amounts ERCOT owes to Participant by the amount of any sums owed by Participant to ERCOT, including any amounts owed pursuant to the operation of the Protocols.

(2) Participant's Remedies for Default.

(a) Unless otherwise specified in this Agreement or in the ERCOT Protocols, and subject to the provisions of Section 12, Dispute Resolution, of this Agreement, in the event of a Default by ERCOT, Participant's remedies shall be limited to:

(i) Immediate termination of this Agreement upon written notice to ERCOT;

(ii) Monetary recovery in accordance with the Settlement procedures set forth in the ERCOT Protocols; and

(iii) Specific performance.

(b) However, in the event of a material breach by ERCOT of any of its representations, warranties or covenants, Participant's sole remedy shall be immediate termination of this Agreement upon written notice to ERCOT.

(3) A Default or breach of this Agreement by a Party shall not relieve either Party of the obligation to comply with the ERCOT Protocols.

C. Force Majeure.

(1) If, due to a Force Majeure Event, either Party is in breach of this Agreement with respect to any obligation hereunder, such Party shall take reasonable steps, consistent with Good Utility Practice, to remedy such breach. If either Party is unable to fulfill any obligation by reason of a Force Majeure Event, it shall give notice and the full particulars of the obligations affected by such Force Majeure Event to the other Party in writing or by telephone (if followed by written notice) as soon as reasonably practicable, but not later than fourteen (14) calendar days, after such Party becomes aware of the event. A failure to give timely notice of the Force Majeure event shall constitute a waiver of the claim of Force Majeure Event. The Party experiencing the Force Majeure Event shall also provide notice, as soon as reasonably practicable, when the Force Majeure Event ends.

(2) Notwithstanding the foregoing, a Force Majeure Event does not relieve a Party affected by a Force Majeure Event of its obligation to make payments or of any consequences of non-performance pursuant to the ERCOT Protocols or under this Agreement, except that the excuse from Default provided by subsection 10(A)(5) above is still effective.

D. Duty to Mitigate. Except as expressly provided otherwise herein, each Party shall use commercially reasonable efforts to mitigate any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Section 11. Limitation of Damages and Liability and Indemnification.

A. EXCEPT AS EXPRESSLY LIMITED IN THIS AGREEMENT OR THE ERCOT PROTOCOLS, ERCOT OR PARTICIPANT MAY SEEK FROM THE OTHER, THROUGH APPLICABLE DISPUTE RESOLUTION PROCEDURES SET FORTH IN THE ERCOT PROTOCOLS, ANY MONETARY DAMAGES OR OTHER REMEDY OTHERWISE ALLOWABLE UNDER TEXAS LAW, AS DAMAGES FOR DEFAULT OR BREACH OF THE OBLIGATIONS UNDER THIS AGREEMENT; PROVIDED, HOWEVER, THAT NEITHER PARTY IS LIABLE TO THE OTHER FOR ANY SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY THAT MAY OCCUR, IN WHOLE OR IN PART, AS A RESULT OF A DEFAULT UNDER THIS AGREEMENT, A TORT, OR ANY OTHER CAUSE, WHETHER OR NOT A PARTY HAD KNOWLEDGE OF THE CIRCUMSTANCES THAT RESULTED IN THE SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY, OR COULD HAVE FORESEEN THAT SUCH DAMAGES OR INJURY WOULD OCCUR.

B. With respect to any dispute regarding a Default or breach by ERCOT of its obligations under this Agreement, ERCOT expressly waives any Limitation of Liability to which it may be entitled under the Charitable Immunity and Liability Act of 1987, Tex. Civ. Prac. & Rem. Code §84.006, or successor statute.

C. The Parties have expressly agreed that, other than subsections A and B of this Section, this Agreement shall not include any other limitations of liability or indemnification provisions, and that such issues shall be governed solely by applicable law, in a manner consistent with Section 13(A), Choice of Law and Venue, of this Agreement, regardless of any contrary provisions that may be included in or subsequently added to the ERCOT Protocols (outside of this Agreement).

Section 12. Dispute Resolution.

A. In the event of a dispute, including a dispute regarding a Default, under this Agreement, Parties to this Agreement shall first attempt resolution of the dispute using the applicable dispute resolution procedures set forth in the ERCOT Protocols.

B. In the event of a dispute, including a dispute regarding a Default, under this Agreement, each Party shall bear its own costs and fees, including, but not limited to attorneys' fees, court costs, and its share of any mediation or arbitration fees.

Section 13. Miscellaneous.

A. Choice of Law and Venue. Notwithstanding anything to the contrary in this Agreement, this Agreement shall be deemed entered into and performable solely in Texas and, with the exception of matters governed exclusively by federal law, shall be governed by and construed and interpreted in accordance with the laws of the State of Texas that apply to contracts executed in and performed entirely within the State of Texas, without reference to any rules of conflict of laws. Neither Party waives primary jurisdiction as a defense; provided that any court suits regarding this Agreement shall be brought in a state or federal court located within Travis County, Texas, and the Parties hereby waive any defense of forum non-conveniens, except defenses under Tex. Civ. Prac. & Rem. Code §15.002(b).

B. Assignment.

(1) Notwithstanding anything herein to the contrary, a Party shall not assign or otherwise transfer all or any of its rights or obligations under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld or delayed, except that a Party may assign or transfer its rights and obligations under this Agreement without the prior written consent of the other Party (if neither the assigning Party or the assignee is then in Default of any Agreement with ERCOT):

(a) Where any such assignment or transfer is to an Affiliate of the Party; or

(b) Where any such assignment or transfer is to a successor to or transferee of the direct or indirect ownership or operation of all or part of the Party, or its facilities; or

(c) For collateral security purposes to aid in providing financing for itself, provided that the assigning Party will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by either Party pursuant to this Section will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). If requested by the Party making any such collateral assignment to a Financing Person, the other Party shall execute and deliver a consent to such assignment containing customary provisions, including representations as to corporate authorization, enforceability of this Agreement and absence of known Defaults, notice of material breach pursuant to Section 10(A), notice of Default, and an opportunity for the Financing Person to cure a material breach pursuant to Section 10(A) prior to it becoming a Default.

(2) An assigning Party shall provide prompt written notice of the assignment to the other Party. Any attempted assignment that violates this Section is void and ineffective. Any assignment under this Agreement shall not relieve either Party of its obligations under this Agreement, nor shall either Party's obligations be enlarged, in whole or in part, by reason thereof.

C. <u>No Third Party Beneficiary.</u> Except with respect to the rights of the Financing Persons in subsection 13(B)(1)(c), (a) nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, (b) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, and (c) this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third party beneficiary to this Agreement or the services to be provided hereunder. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

D. <u>No Waiver.</u> Parties shall not be required to give notice to enforce strict adherence to all provisions of this Agreement. No breach or provision of this Agreement shall be deemed waived, modified or excused by a Party unless such waiver, modification or excuse is in writing and signed by an authorized officer of such Party. The failure by or delay of either Party in enforcing or exercising any of its rights under this Agreement shall (a) not be deemed a waiver, modification or excuse of such right or of any breach of the same or different provision of this Agreement, and (b) not prevent a subsequent enforcement or exercise of such right. Each Party shall be entitled to enforce the other Party's covenants and promises contained herein, notwithstanding the existence of any claim or cause of action against the enforcing Party under this Agreement or otherwise.

E. <u>Headings.</u> Titles and headings of paragraphs and sections within this Agreement are provided merely for convenience and shall not be used or relied upon in construing this Agreement or the Parties' intentions with respect thereto.

F. Severability. In the event that any of the provisions, or portions or applications thereof, of this Agreement is finally held to be unenforceable or invalid by any court of competent jurisdiction, that determination shall not affect the enforceability or validity of the remaining portions of this Agreement, and this Agreement shall continue in full force and effect as if it had been executed without the invalid provision; provided, however, if either Party determines, in its sole discretion, that there is a material change in this Agreement by reason thereof, the Parties shall promptly enter into negotiations to replace the unenforceable or invalid provision with a valid and enforceable provision. If the Parties are not able to reach an agreement as the result of such negotiations within fourteen (14) days, either Party shall have the right to terminate this Agreement on three (3) days written notice.

G. Entire Agreement. Any exhibits attached to this Agreement are incorporated into this Agreement by reference and made a part of this Agreement as if repeated verbatim in this Agreement. This Agreement represents the Parties' final and mutual understanding with respect to its subject matter. It replaces and supersedes any prior agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by any Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement. An agreement, statement, or promise not contained in this Agreement is not valid or binding.

H. Amendment. The standard form of this Agreement may only be modified through the procedure for modifying ERCOT Protocols described in the ERCOT Protocols. Any changes to the terms of the standard form of this Agreement shall not take effect until a new Agreement is executed between the Parties.

I. ERCOT's Right to Audit Participant. Participant shall keep detailed records for a period of three years of all activities under this Agreement giving rise to any information, statement, charge, payment or computation delivered to ERCOT under the ERCOT Protocols. Such records shall be retained and shall be available for audit or examination by ERCOT as hereinafter provided. ERCOT has the right during Business Hours and upon reasonable written notice and for reasonable cause to examine the records of Participant as necessary to verify the accuracy of any such information, statement, charge, payment or computation made under this Agreement. If any such examination reveals any inaccuracy in any such information, statement, charge, payment or computation, the necessary adjustments in such information, statement, charge, payment, computation, or procedures used in supporting its ongoing accuracy will be promptly made.

J. Participant's Right to Audit ERCOT. Participant's right to data and audit of ERCOT shall be as described in the ERCOT Protocols and shall not exceed the rights described in the ERCOT Protocols.

K. Further Assurances. Each Party agrees that during the term of this Agreement it will take such actions, provide such documents, do such things and provide such further assurances as may reasonably be requested by the other Party to permit performance of this Agreement.

L. Conflicts. This Agreement is subject to applicable federal, state, and local laws, ordinances, rules, regulations, orders of any Governmental Authority and tariffs. Nothing in this Agreement may be construed as a waiver of any right to question or contest any federal, state and local law, ordinance, rule, regulation, order of any Governmental Authority, or tariff. In the event of a conflict between this Agreement and an applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff, the applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff shall prevail, provided that Participant shall give notice to ERCOT of any such conflict affecting Participant. In the event of a conflict between the ERCOT Protocols and this Agreement, the provisions expressly set forth in this Agreement shall control.

M. No Partnership. This Agreement may not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party has any right, power, or authority to enter any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

N. Construction. In this Agreement, the following rules of construction apply, unless expressly provided otherwise or unless the context clearly requires otherwise:

(1) The singular includes the plural, and the plural includes the singular.

(2) The present tense includes the future tense, and the future tense includes the present tense.

(3) Words importing any gender include the other gender.

(4) The word “shall” denotes a duty.

(5) The word “must” denotes a condition precedent or subsequent.

(6) The word “may” denotes a privilege or discretionary power.

(7) The phrase “may not” denotes a prohibition.

(8) References to statutes, tariffs, regulations, or ERCOT Protocols include all provisions consolidating, amending, or replacing the statutes, tariffs, regulations, or ERCOT Protocols referred to.

(9) References to “writing” include printing, typing, lithography, and other means of reproducing words in a tangible visible form.

(10) The words “including,” “includes,” and “include” are deemed to be followed by the words “without limitation.”

(11) Any reference to a day, week, month or year is to a calendar day, week, month or year unless otherwise indicated.

(12) References to articles, Sections (or subdivisions of Sections), exhibits, annexes or schedules are to this Agreement, unless expressly stated otherwise.

(13) Unless expressly stated otherwise, references to agreements, ERCOT Protocols and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent the amendments and other modifications are not prohibited by this Agreement.

(14) References to persons or Entities include their respective successors and permitted assigns and, for governmental Entities, Entities succeeding to their respective functions and capacities.

(15) References to time are to Central Prevailing Time (CPT).

O. Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED, AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.

Electric Reliability Council of Texas, Inc.:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Participant:

By: ______________________________

Name:

Title:

Date:

Market Participant Name:

Market Participant DUNS:

ERCOT Nodal Protocols

Section 22

Attachment E: Notification of Suspension of Operations

February 12, 2020

Notification of Suspension of Operations of a Generation Resource

This Notification is required for providing notification of any Generation Resource suspension lasting greater than 180 days. Information may be inserted electronically to expand the reply spaces as necessary.

The Notification must be signed, notarized and delivered to ERCOT. Delivery may be accomplished via email to MPRegistration@ercot.com (if a scanned copy) or via facsimile (Attention: Market Participant Registration) at (512) 225-7079.

ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

Part I:

Resource Entity: ______________________

DUNS Number: ______________________

Resource Site Name: ___________________

Resource Site Location (County): _____________________

Unit Name(s): __________________

Resource Name(s) (Unit Code/Mnemonic): ___________________

ESI ID: ____

Seasonal Net Max Sustainable Rating – Summer (MW): _____________________

Seasonal Net Minimum Sustainable Rating – Summer (MW): ______________________

Part II:

As of _____ [date],[1] the Generation Resource(s) will be limited or unavailable for Dispatch by ERCOT because Resource Entity will [check one]:

☐ decommission and retire the Generation Resource(s) permanently,[2]

☐ suspend operation on a year-round basis (i.e., mothball) and begin operation on a seasonal basis with a Seasonal Operation Period that begins on _____ and ends on _____ [dates]. The Seasonal Operation Period must be inclusive of June 1 through September 30,

☐ suspend operation (*i.e.*, mothball) of the Generation Resource(s) for a period of not less than ___ months and not greater than ___ months, or

☐ suspend operation (*i.e.*, mothball) of the Generation Resource(s) indefinitely, or

☐ suspend operation of the Generation Resource(s) due to a Forced Outage. Resource Entity intends to bring the Generation Resource(s) back to service on [Date].

Unless the Generation Resource(s) will be decommissioned and retired the estimated time to return the suspended Generation Resource(s) to service is ___ months.

Check if applicable: ☐ Resource Entity believes that this Generation Resource(s) is inoperable due to emissions limitations or not being repairable.

Operational and Environmental Limitations (check and describe all that apply):

(a) Operational:

☐ Maximum annual hours of operation: ____________

☐ Maximum annual MWhs: _______________

☐ Maximum annual starts: ________________

☐ Other: _____________

(b) Environmental:

☐ Maximum annual NOx emissions: ______________

---

[1] Pursuant to Protocol Section 3.14.1.1, Notification of Suspension of Operations, this date must be at least 150 days (or 90 days if the Generation Resource will mothball and operate under a Seasonal Operation Period) from the date ERCOT receives this Notification, unless the suspension is the result of a Forced Outage, in which case the Generation Resource shall submit this Notification as soon as practicable.

[2] ERCOT will remove the Generation Resource(s) from its registration systems if this option is selected.

☐ Maximum annual SO2 emissions: ______________

☐ Other: ____________

Part III:

Estimated RMR Fuel Adder ($/MMBtu): ____________________

Proposed Initial Standby Cost ($/hr): _________________

I understand and agree that this Notification is not confidential and does not constitute Protected Information under the ERCOT Protocols.

I hereby certify that the proposed, estimated Fuel Adder, Standby Costs, and attached budget are accurate at the time of submittal, necessary, and do not exceed fair-market value.

The undersigned certifies that I am an officer or executive of Resource Entity, that I am authorized to execute and submit this Notification on behalf of Resource Entity, and that the statements contained herein are true and correct.

____

Name: _____________

Title: _____________

Date: _____________

STATE OF _______________

COUNTY OF _____________

Before me, the undersigned authority, this day appeared ___________________, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

> "I am an officer of ______________, I am authorized to execute and submit the foregoing Notification on behalf of ______________, and the statements contained in such Notification are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the _____ day of ____________, 20__.

____

Notary Public, State of ___________

My Commission expires __________

ERCOT Nodal Protocols

Section 22

Attachment F: [RESERVED]

February 12, 2020

ERCOT Nodal Protocols

Section 22

Attachment G: Standard Form Emergency Response Service Agreement

June 1, 2013

Standard Form Emergency Response Service (ERS)
Supplement to Market Participant Agreement
Between
(Name of Participant)
and
Electric Reliability Council of Texas, Inc.

This Supplement to Market Participant Agreement (“Supplement”), effective as of [START DATE] (“Start Date”), is entered into by and between [PARTICIPANT’s NAME], a Qualified Scheduling Entity in the ERCOT Region (“QSE” or “Participant”) and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation (“ERCOT”).[1]

Recitals

WHEREAS:

A. The Public Utility Commission of Texas (“PUCT”) instituted its Substantive Rule 25.507, “Electric Reliability Council of Texas (ERCOT) Emergency Response Service” (“ERS Rule”) providing for ERCOT’s administration of a special emergency service known as Emergency Response Service (“ERS”); and

B. Participant is a QSE in the ERCOT Region and has executed a Standard Form Market Participant Agreement (“Market Participant Agreement”) with ERCOT; and

C. Participant is the QSE representing an entity or entities controlling ERS Resource(s) that will be obligated to provide ERS within a competitive service territory or a Non-Opt In Entity (“NOIE”) service territory after obtaining written authorization from the NOIE; and

D. Participant and ERCOT wish to supplement the Market Participant Agreement between Participant and ERCOT to provide for Participant to represent ERS Resources wishing to participate in the ERS; and

E. The Parties enter into this Supplement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities with respect to ERS.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the “Parties”) hereby agree as follows:

---

[1] Unless otherwise indicated, capitalized terms in this Agreement have the meanings ascribed to them in the ERCOT Protocols.

A. All terms and conditions of the Market Participant Agreement between Participant and ERCOT remain in full force and effect.

B. In addition to its obligations under the Market Participant Agreement with ERCOT, Participant will submit offers for ERS on behalf of the entities determined by Participant to be qualified to provide ERS for a particular Contract Period as described in a Request for Proposal issued by ERCOT.

C. Participant and ERCOT will abide by and comply with the ERS Rule as well as all ERCOT Protocols and Technical Requirements concerning ERS.

D. Participant and ERCOT agree that each award of ERS will be confirmed by a terms and conditions sheet ("Award Notification") provided by ERCOT to Participant.

E. Either Party may terminate this Supplement by providing 30 days notice to the other Party; *provided, however,* no termination of this Supplement will be effective before the end of an ERS Contract Period for which ERCOT has already issued an Award Notification to Participant.

F. This Supplement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED, AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that s/he has full power and authority to execute this Supplement.

Electric Reliability Council of Texas, Inc.:

By: ____

Printed Name: ______________________________________

Title: ____

Date: ____

Participant:

By: ____

Printed Name:______________________________________

Title: ____

Date: ____

ERCOT Nodal Protocols

Section 22

Attachment H: Notification of Change of Generation Resource Designation

December 17, 2021

Notification of Change of Generation Resource Designation

This Notification is for changing a Generation Resource designation in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary.

The Notification must be signed, notarized and delivered to ERCOT. Delivery may be accomplished via email to MPRegistration@ercot.com (if a scanned copy) or via facsimile (Attention: Market Participant Registration) at (512) 225-7079. ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

Resource Entity: ______________________________

DUNS No.: ______________________________

Generation Resource(s) [plant and unit number(s)] ____________________

Generation Resource(s) is currently [check one]

☐ decommissioned and retired

☐ under a Reliability Must-Run (RMR) Agreement

☐ mothballed under a Seasonal Operation Period

☐ mothballed

As of _______ [date], Resource Entity will change the Generation Resource(s) designation to [check one]

☐ operational (for a Mothballed Generation Resource operating under a Seasonal Operation Period, selecting this option means that the Generation Resource is returning to year round service)

☐ mothballed (a Mothballed Generation Resource operating under a Seasonal Operation Period may not select this option, and must instead use the Section 22, Attachment E, Notification of Suspension of Operation form to change to a different mothballed status)

☐ decommissioned and retired permanently[1] (a Mothballed Generation Resource operating under a Seasonal Operation Period may not select this option and must instead use the form in Section 22, Attachment E to be designated as decommissioned)

---

[1] In accordance with Section 3.14.1.9, Generation Resource Status Updates, ERCOT will remove the Generation Resource(s) from its registration upon Resource Entity updating Resource Registration accordingly.

☐ Mothballed Generation Resource operating under a Seasonal Operation Period, updating start date or end date of Seasonal Operation Period

As of _________ [date], a Mothballed Generation Resource will change its Seasonal Operation Period as follows:

☐ change start date of Seasonal Operation Period from _____ to _____

☐ change end date of Seasonal Operation Period from _____ to _____

The undersigned certifies that I am an officer of Resource Entity, that I am authorized to execute and submit this Notification on behalf of Resource Entity, and that the statements contained herein are true and correct.

____

Name: ____________________________

Title: ____________________________

Date: ____________________________

STATE OF _______________

COUNTY OF _____________

Before me, the undersigned authority, this day appeared __________________, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

> "I am an officer of _____________, I am authorized to execute and submit the foregoing Notification on behalf of _____________, and the statements contained in such Notification are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the _____ day of ___________, 20__.

____

Notary Public, State of ___________

My Commission expires __________

ERCOT Nodal Protocols

Section 22

Attachment I: Amendment to Standard Form Black Start Agreement

January 1, 2013

Amendment to
Standard Form Black Start Agreement
Between
(Name of Participant)
and
Electric Reliability Council of Texas, Inc.

This AMENDMENT to the Standard Form Black Start Agreement ("Amendment"), effective as of the ___________ day of ____________________, ___________ ("Effective Date"), is entered into by and between (Participant), a [State of Registration and Entity Type] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS, Participant and ERCOT entered into a Standard Form Black Start Agreement (Agreement) dated ______________; and

WHEREAS, Participant and ERCOT wish to amend that Agreement to substitute the current Black Start Resource with an alternative Generation Resource that will now serve as the designated Black Start Resource under the Agreement.

NOW, THEREFORE, Participant and ERCOT agree that paragraphs (A) and (B) of Section 1, Resource-Specific Terms, of that Agreement shall be deleted in its entirety and replaced with the following:

Section 1. Resource-Specific Terms.

A. Start Date: ____________________.

B. Black Start Resource.

(1) Description of Black Start Resource [including location, number of generators, metering scheme, etc.]:

____
____, as described in more detail on Exhibit 1.

(2) Nameplate Capacity in MW: _____

(3) Delivery Point: ____________________________

(4) Revenue Meter Location (use Resource IDs): __________________________

This Amendment modifies the existing Agreement only to include the Resource-specific terms designated above by Participant.

This Amendment in no way alters the terms and conditions of the existing Agreement other than as specifically set forth herein.

SIGNED, ACCEPTED AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Amendment to the Standard Form Black Start Agreement.

Electric Reliability Council of Texas, Inc.:

By: ____

Name: ____

Title: ____

Date: ____

Participant:

By: ____

Name: ____

Title: ____

Date: ____

Market Participant Name: ____

Market Participant DUNS: ____

ERCOT Nodal Protocols

Section 22

Attachment J: Annual Certification Form to Meet ERCOT Additional Minimum Participation Requirements

October 1, 2013

Annual Certification Form
to Meet ERCOT Additional
Minimum Participation Requirements

Counter-Party Name: ____
(“Counter-Party”)

I, ____, a duly authorized officer or executive of Counter-Party, understanding that Electric Reliability Council of Texas, Inc. (“ERCOT”) is relying on this Certification as evidence that Counter-Party meets the minimum participation requirements set forth in the ERCOT Protocols, hereby represent that I have full authority to bind the Counter-Party and further certify and represent the following:

1. **<u>Expertise in Markets.</u>** All employees or agents transacting in ERCOT markets pursuant to the ERCOT Protocols have had appropriate training and/or experience and are qualified and authorized to transact on behalf of the Counter-Party.

2. **<u>Market Operational Capabilities.</u>** Counter-Party has appropriate market operating procedures and technical abilities to promptly and effectively respond to all ERCOT market communications.

3. **<u>Capitalization.</u>** Counter-Party has read and agrees to the capitalization requirements as detailed in the ERCOT Protocols.

4. **<u>Risk Management Capabilities.</u>** Counter-Party maintains appropriate, comprehensive risk management capabilities with respect to the ERCOT markets in which the Counter-Party transacts or wishes to transact.

5. **<u>Verification of Risk Management Framework.</u>** Counter-Party has read and agrees to the requirements for verification of its risk management framework as detailed in the ERCOT Protocols.

   Risk management framework verification processes undertaken by ERCOT or a third party acting on ERCOT’s behalf are by necessity limited in scope and nature and cannot address their appropriateness or sufficiency with respect to the full range of risks that may face a Counter-Party or that all such capabilities and controls are in fact operating as purported. In performing an assessment of risk management framework, ERCOT or its agent rely on the assertions and documentary evidence produced by the Counter-Party, and accept no liability for the consequences of insufficient implementation or effectiveness in mitigating risks of the Counter-Party or the impact of risks upon the financial strength of the Counter-Party with respect to ERCOT or other Independent System Operator/Regional Transmission Operator - administered markets.

☐ By checking this box, I further certify and represent that there has been no material change in internal risk management capabilities since last verified by ERCOT.

☐ By checking this box, I further certify and represent that Counter-Party is:

(a) An "Appropriate Person" as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 6(c)(3)(A)-(J));

(b) An "Eligible Contract Participant" as defined in section 1a(18)(A) of the Commodity Exchange Act (7 U.S.C. § 1a(18)(A)) and in Commodity Futures Trading Commission (CFTC) regulation 1.3(m) (17 C.F.R. § 1.3(m)); or

(c) In the business of:

  (i) Generating, transmitting or distributing electric energy; or

  (ii) Providing electric energy services that are necessary to support the reliable operation of the transmission system.

This area is provided for the Counter-Party to provide any additional information or clarification necessary with respect to this Certification.

Date: ______________________________________

Signature: __________________________________

Print Name: ________________________________

Title: ______________________________________

Subscribed and sworn before me ________________________ a notary public in the State of ___________________in and for the County of _________________, this ____ day of ________, 20__.

____
(Notary Public Signature)

My commission expires: ____/____/__

ERCOT Nodal Protocols

Section 22

Attachment K: Declaration of Natural Gas Pipeline Coordination

January 27, 2023

Declaration of Natural Gas Pipeline Coordination

This declaration applies to the following Generation Resources (list by Resource Site Code):
List Generation Resource(s) by Resource Site Code

Natural Gas Pipeline Coordination

INSTRUCTIONS: Use this section for Generation Resources relying on natural gas as the primary fuel source. Repeat the following for each applicable Generation Resource.

Generation Resource (provide Resource Site Code):

(1) Identify the natural gas pipelines directly connected to the Generation Resource and contact information (name, phone number, and email) for each natural gas pipeline operator:

(2) If a natural gas pipeline operator did not respond to the Resource Entity's documented effort to coordinate, check the box below and identify the natural gas pipeline operator.

☐ No response was received from the following natural gas pipeline operator:

(3) If a natural gas pipeline operator responded to the Resource Entity's documented effort to coordinate and disclose activities or conditions materially increasing the risk of Generation Resource unavailability in the summer Peak Load Season, please disclose the following information:

(a) The name or identifier of the natural gas pipeline:

(b) The operator of the natural gas pipeline:

(c) Impacts the activity or condition may have on the Generation Resource's availability (e.g., could cause an Outage or derate):

(d) The time period during which the activity or condition is expected to occur, including expected duration:

(e) Other useful information:

(4) If contract language prohibits the Resource Entity from disclosing any of the information requested in 3(a)-(e) above and the natural gas pipeline operator refused the Resource Entity's documented effort to obtain consent to disclose that information to ERCOT, check the box below and identify the natural gas pipeline operator.

☐ Contract language prohibits disclosure and the following natural gas pipeline operator(s) would not consent to information disclosure:

ERCOT Nodal Protocols

Section 22

Attachment L: Declaration of Private Use Network Net Generation Capacity Availability

February 1, 2022

Declaration of Private Use Network Net Generation Capacity Availability

A Private Use Network is an electric network connected to the ERCOT Transmission Grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation). A Resource Entity that represents a Generation Resource or a Settlement Only Resource (SOG) in a Private Use Network shall use this form to provide ERCOT with information required by ERCOT Protocol Section 10.3.2.4, Reporting of Net Generation Capacity. This form must be submitted to ERCOT by February 1 of each year. ERCOT shall treat this information as Protected Information in accordance with paragraph (1)(x) of Section 1.3.1.1, Items Considered Protected Information.

Please fill out this form electronically, print and sign. The form can be sent to ERCOT via email to MPRegistration@ercot.com (.pdf), via facsimile to (512) 225-7079, or via mail to ERCOT, Attention: Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744.

Date of Notice: ________________

Resource Entity: ______________________ DUNS Number: ________________

Facility Name: ________________

In the table below, enter the incremental forecasted changes in net generation capacity (in Megawatts) available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and year-on-year changes as of May 31 for the next 10 subsequent years. The capacity forecasts should account for changes in both process loads and self-generation capability. <u>Example</u>: If the capacity change is -75 MW from May 31 of the previous calendar year to May 31 of the current year, enter -75 MW in line 1. If the capacity change is 100 MW from May 31 of the current calendar year to May 31 of the next calendar year, enter 100 MW in line 2. DO NOT enter cumulative annual changes. (For this example, do not enter 25 MW in line 2).

Line#	Annual Forecast Periods	Expected Change in Net Generation Capacity Available to the ERCOT Grid, MW
1	May 31 of previous calendar year to May 31 of current calendar year	
2	May 31 of current calendar year to May 31 of forecast year 1	
3	May 31 of forecast year 1 to May 31 of forecast year 2	
4	May 31 of forecast year 2 to May 31 of forecast year 3	
5	May 31 of forecast year 3 to May 31 of forecast year 4	
6	May 31 of forecast year 4 to May 31 of forecast year 5	
7	May 31 of forecast year 5 to May 31 of forecast year 6	
8	May 31 of forecast year 6 to May 31 of forecast year 7	
9	May 31 of forecast year 7 to May 31 of forecast year 8	
10	May 31 of forecast year 8 to May 31 of forecast year 9	
11	May 31 of forecast year 9 to May 31 of forecast year 10	

Describe any future load expansions, equipment shutdowns, or new self-generation associated with the capacity changes reported above.

By signing below, I certify that I am authorized to execute and submit this Notice on behalf of the above Resource Entity, and that the data and statements contained herein are true and correct to the best of my knowledge.

Signature of Authorized Signatory: ______________________________

Name: ________________________________

Title: ________________________________

Phone: ________________

Date: ________________

[NPRR995: Replace Section 22, Attachment L above with the following upon system implementation:]

Declaration of Private Use Network Net Generation Capacity Availability

A Private Use Network is an electric network connected to the ERCOT Transmission Grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation). A Resource Entity that represents a Generation Resource, a Settlement Only Generator (SOG), or a Settlement Only Energy Storage System (SOESS) in a Private Use Network shall use this form to provide ERCOT with information required by ERCOT Protocol Section 10.3.2.4, Reporting of Net Generation Capacity. This form must be submitted to ERCOT by February 1 of each year. ERCOT shall treat this information as Protected Information in accordance with paragraph (1)(x) of Section 1.3.1.1, Items Considered Protected Information.

Please fill out this form electronically, print and sign. The form can be sent to ERCOT via email to MPRegistration@ercot.com (.pdf), via facsimile to (512) 225-7079, or via mail to ERCOT, Attention: Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744.

Date of Notice: ________________

Resource Entity: ____________________ DUNS Number: ________________

Facility Name: ________________

In the table below, enter the incremental forecasted changes in net generation capacity (in Megawatts) available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and year-on-year changes as of May 31 for the next 10 subsequent years. The capacity forecasts should account for changes in both process loads and self-generation capability. Example: If the capacity change is -75 MW from May 31 of the previous calendar year to May 31 of the current year, enter -75 MW in line 1. If the capacity change is 100 MW from May 31 of the current calendar year to May 31 of the next calendar year, enter 100 MW in line 2. DO NOT enter cumulative annual changes. (For this example, do not enter 25 MW in line 2).

Line#	Annual Forecast Periods	Expected Change in Net Generation Capacity Available to the ERCOT Grid, MW
1	May 31 of previous calendar year to May 31 of current calendar year	
2	May 31 of current calendar year to May 31 of forecast year 1	
3	May 31 of forecast year 1 to May 31 of forecast year 2	
4	May 31 of forecast year 2 to May 31 of forecast year 3	
5	May 31 of forecast year 3 to May 31 of forecast year 4	
6	May 31 of forecast year 4 to May 31 of forecast year 5	

7	May 31 of forecast year 5 to May 31 of forecast year 6	
8	May 31 of forecast year 6 to May 31 of forecast year 7	
9	May 31 of forecast year 7 to May 31 of forecast year 8	
10	May 31 of forecast year 8 to May 31 of forecast year 9	
11	May 31 of forecast year 9 to May 31 of forecast year 10	

Describe any future load expansions, equipment shutdowns, or new self-generation associated with the capacity changes reported above.

By signing below, I certify that I am authorized to execute and submit this Notice on behalf of the above Resource Entity, and that the data and statements contained herein are true and correct to the best of my knowledge.

Signature of Authorized Signatory: ______________________________

Name: ________________________________

Title: ________________________________

Phone: ________________

Date: ________________

ERCOT Nodal Protocols

Section 22

Attachment M: Generation Resource Disclosure Regarding Bids for Black Start Service

August 1, 2022

Generation Resource Disclosure Regarding Bids for Black Start Service

Resource Entity:

Qualified Scheduling Entity (QSE) representing the Resource Entity:

Generation Resource (list by Resource Site Code):

Operational Weather limitations:

(1) Minimum Ambient Operation Temperature (°F)

(2) Maximum Ambient Operation Temperature (°F)

(3) Relative Humidity (%)

Weather Related Limitation Disclosure:
Please list any weather-related limitations to the Generation Resource's start-up/operation capabilities (include a brief description of the limitation(s), planned remediation for the limitation, and an associated target completion date for the remediation): ____
____
____

Weatherization affirmation – please affirm by checking the box:
☐ I hereby affirm that all disclosed weather-related limitations listed above and weatherization preparations for equipment critical to providing Black Start Service (BSS) are complete or will be completed prior to the beginning of Black Start qualification testing.

BSS Back-up Fuel capability:

(1) Contracted number of hours at maximum output utilizing BSS Back-up Fuel

BSS Back-up Fuel affirmation – please affirm by checking the box:
☐ I hereby affirm that the Generation Resource will maintain sufficient BSS Back-up Fuel to operate at its maximum output for the number of hours disclosed above prior to the beginning of Black Start qualification testing and for the duration of the BSS contract term.

By signing below, I certify that I am an officer or authorized executive of each Resource Entity listed above, that I am authorized to execute and submit this declaration on behalf of each Resource Entity listed above, and that the statements contained herein are true and correct.

____
Signature

____
Name

____
Title

____
Date

ERCOT Nodal Protocols

Section 22

Attachment N: Standard Form Must-Run Alternative Agreement

July 1, 2019

[NPRR885: Insert Section 22 Attachment N below upon system implementation:]

Standard Form Must-Run Alternative
Supplement to the Market Participant Agreement
Between
(Name of Participant)
and
Electric Reliability Council of Texas, Inc.

This Must-Run Alternative Service Supplement to the Market Participant Agreement (“Agreement”), effective as of the __________ day of _______________, ___________ (“Effective Date”), is entered into by and between [insert Participant’s name], a [insert business Entity type and state] (“Participant”) and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation (“ERCOT”).

Recitals

WHEREAS:

A. Participant is a Qualified Scheduling Entity (QSE) as defined in the ERCOT Protocols, has executed a Standard Form Market Participant Agreement (“Market Participant Agreement”) with ERCOT, and intends to provide Must-Run Alternative (MRA) Service;

B. ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;

C. On _______, 20__, ERCOT issued a Request for Proposals (“MRA RFP”) seeking offers from QSEs able to provide MRA Service;

D. Participant submitted an offer to provide MRA Service in response to the RFP that satisfies the requirements for MRA Service, as set forth in the ERCOT Protocols;

E. Pursuant to PUC Substantive Rule 25.502, the ERCOT Board of Directors has approved a recommendation to enter into this Agreement;

F. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the “Parties”) hereby agree as follows:

Section 1. MRA Terms.

A. Start Date: _______________, 20_____.

B. Stop Date: _______________, 20_____.

C. MRA: __________________________.

D. Description of MRA or, if an aggregation, MRA Sites [*including location(s), type(s) of unit, etc.]:*

____

____.

E. MRA Information

(1) MRA Contracted Capacity, Target Availability and Standby Price for each MRA Contracted Month

MRA Contracted Month - Year	MRA Contracted Hours (whole Hours Ending (HEs))	Capacity (MW per hr)	Days of Week	Target Availability (%)	Standby Price ($/MW per hr)

(2) MRA Contributed Capital Expenditures

Month - Year	Capital Expenditure ($)

(3) Data for MRA deployment event compensation

(a) Proxy Fuel Consumption (MMBtu/Deployment Event): __________, or

(b) Event Deployment Price ($/Deployment Event): __________

(c) Ramp period or start-up time (hrs): _________

(4) Data needed for variable compensation

(a) Proxy Heat Rate (MMBtu/MWh): __________, and/or

(b) Variable Price ($/MWh): __________

(5) Proxy Fuel Adder Price ($/MMBtu): __________

F. For Thermal and Non-Thermal Generators (Transmission or Distribution Connected)

(1) Delivery Point:_______

(2) Revenue Meter Location (Use Resource ID):__________

[If multiple MRAs awarded to a single QSE, duplicate Sections 1(A)-1(F) for each MRA here]

Section 2. Additional Terms.

A. The terms and conditions of the Market Participant Agreement between Participant and ERCOT remain in full force and effect.

B. Participant agrees to make available for ERCOT's use the MRA Service described in Section I of this Agreement, in accordance with and subject to ERCOT Protocols, the Market Participant Agreement, and the MRA RFP, all of which are hereby incorporated by reference.

C. Term of Agreement

(1) This Agreement is effective beginning on the Effective Date, subject to paragraph 2(F) below.

(2) The Term of this Agreement begins at 0000 hours on the Start Date and ends at 2400 hours on the Stop Date.

D. Except as provided in paragraphs 2(E) and 2(F) below, this Agreement terminates upon the completion of all obligations under the terms of this Agreement, provided that the Term of this Agreement may be extended for a period of up to 90 days if, in ERCOT's sole discretion, such an extension is necessary. ERCOT shall provide written notice of such an extension no later than 30 days before the date the extension is to begin.

E. ERCOT, at its sole discretion, may terminate the Parties' obligations under this Agreement with respect to any MRA listed in Section 1 above at any time upon 90 days' notice if it determines that the MRA Service provided by the MRA is no longer necessary. If more than one MRA is listed in Section 1, the Parties' obligations under this Agreement will continue with respect to any MRA not terminated pursuant to this paragraph.

F. Participant may, at its option, immediately terminate this Agreement upon the failure of ERCOT to continue to be certified by the PUCT as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151.

G. If ERCOT has awarded offers to multiple QSEs for MRA Service in response to a single MRA RFP, this Agreement will be effective only upon written confirmation by ERCOT to Participant that ERCOT has secured fully executed MRA Agreements from each QSE with an awarded offer. This confirmation is a condition precedent to performance of any obligation under this Agreement.

H. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.

I. Payments to Participant for MRA Service shall be made based on the MRA offers awarded by ERCOT and in accordance with the ERCOT Protocols applicable to MRA Service.

J. Automatic Default. The occurrence of either of the following shall constitute an automatic Default by Participant under this Agreement:

(1) The MRA or one or more MRA Sites is abandoned without an intention to return to operation during the term of the MRA Agreement or approval by ERCOT of a substitute MRA or MRA Site in accordance with Protocol Section 3.14.4.3, MRA Substitution; or

(2) Three or more unexcused Misconduct Events, as described in Protocol Section 3.14.4.8, MRA Misconduct Events, occur during the term of the MRA Agreement.

K. Other Default Events. A material failure by Participant to comply with the ERCOT Protocols governing MRA Service, the terms of this Agreement, or the MRA RFP shall constitute a Default unless cured within fourteen (14) Business Days after ERCOT gives notice of the material breach to Participant.

L. Remedies for Default. In addition to ERCOT’s remedies for Default described in the Market Participant Agreement, ERCOT may, in its sole discretion, terminate this Agreement upon seven days’ written notice in the event of Participant’s Default.

M. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED, AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.

Electric Reliability Council of Texas, Inc.:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Participant:

By: ______________________________

Name: ______________________________

Title: _______________________________

Date: _______________________________

Market Participant Name: ____

Market Participant DUNS: ____

ERCOT Nodal Protocols

Section 22

Attachment O: [RESERVED]

January 27, 2023

ERCOT Nodal Protocols

Section 23

Form A: Congestion Revenue Right (CRR) Account Holder Application for Registration

February 1, 2022

Date Received: ______________________

CONGESTION REVENUE RIGHT (CRR) ACCOUNT HOLDER APPLICATION FOR REGISTRATION

This application is for approval as a CRR Account Holder 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), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. In addition to the application, ERCOT must receive an application fee in the amount of $500 via check or wire transfer. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application 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.

☐ **Check if entity is a Non-Opt In Entity (NOIE).**

1. Authorized Representative (“AR”). Defined in Section 2.1, Definitions.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual
☐ Electric Cooperative
☐ Other: _____
☐ Partnership
☐ Limited Liability Company
☐ Municipally Owned Utility
☐ Corporation

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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

7. Allocation Eligibility. Indicate if the Applicant is eligible for the allocation described below:

☐ **Pre-Assigned Congestion Revenue Right (PCRR) Allocations.** ERCOT shall allocate PCRRs to eligible Municipally Owned Utilities (MOUs) and Electric Cooperatives (ECs) pursuant to Section 7.4, Allocation of Pre-Assigned Congestion Revenue Rights.

8. Proposed commencement date for service: _____

PART II – BANKING INFORMATION FOR FUNDS TRANSFERS

1. Banking Information. Applicant must be able to conduct Electronic Funds Transfers (EFTs) for the settlement of financial transactions with ERCOT.

Bank Name:	
Account Name:	
Account No.:	
ABA Number:	

2. Accounts Payable Contact (Settlement & Billing).

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

3. Backup Accounts Payable Contact (Settlement & Billing). *(Optional)*

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

PART III – ADDITIONAL REQUIRED INFORMATION

1. Officers and Principals. Provide the name of all officers and the name and position of all Principals, as defined by Section 16.1.2, Principal of a Market Participant. In addition, ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State 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 the Standard Form Market Participant Agreement (Section 22, Attachment C), Digital Certificate Audit Attestation, 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.)

3. Disclosures. Provide the name of any Principal of the Applicant that is now, or was at any point in time, a Principal of any other Entity that is now, or was at any point in time, a registered ERCOT Market Participant, along with the name of the relevant ERCOT Market Participant and the dates during which the Principal of the Applicant was a Principal of the other Entity.

4. Counter-Party Credit Application. Complete the Counter-Party Credit Application, located at http://www.ercot.com/services/rq/credit, and submit as instructed in conjunction with this application, in accordance with Section 16.8, Registration and Qualification of Congestion Revenue Rights Account Holders.

5. Annual Certification Form to Meet ERCOT Additional Minimum Participation. Complete Section 22 Attachment J, Annual Certification Form to Meet ERCOT Additional Minimum Participation Requirements, and submit in conjunction with this application, pursuant to Section 16.16.3, Verification of Risk Management Framework.

6. Qualified Scheduling Entity (QSE) Acknowledgment. Provide all information requested in Attachment A below and have the document executed by both parties, ***ONLY*** if the Applicant is a Non-Opt-In Entity (NOIE) and eligible for PCRRs.

PART IV – 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

Applicable only if CRRAH is a NOIE and eligible for Pre-Assigned CRRs

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 Nodal Protocols

Section 23

Form B: Load Serving Entity (LSE) Application for Registration

February 1, 2022

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), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. In addition to the application, ERCOT must receive an application fee in the amount of $500 via check or wire transfer, if the applicant is a Retail Electric Provider (REP) and/or Competitive Retailer (CR), per Section 9.16.2, User Fees. 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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual
☐ Electric Cooperative
☐ Other: _____
☐ Partnership
☐ Limited Liability Company
☐ Municipally Owned Utility
☐ Corporation

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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			

Email Address:	

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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 CR or losing CR. Includes TA Business ("TAB"), TA Regulatory ("TAR") and TA Technical ("TAT").

TAB:

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

TAR:

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

TAT:

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:	
Fax:	
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 Nodal Protocols

Section 23

Form C: Managed Capacity Declaration

May 1, 2019

Date Received: ______________________

MANAGED CAPACITY DECLARATION

Pursuant to subsection (d) of P.U.C. SUBST. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas, and Section 3.6.2, Decision Making Entity for a Resource, each Resource Entity shall inform ERCOT of the Decision Making Entity (DME) that controls each Resource that it owns, except for Load Resources that are not Security Constrained Economic Dispatch (SCED) qualified, by completing this Declaration.

If the legal entity that owns a Resource is not registered as a Resource Entity, then the Resource Entity that registered the Resource with ERCOT shall complete this Declaration for the Resource and submit it to ERCOT with a signed acknowledgement from the Resource owner authorizing the Resource Entity to complete this Declaration as the owner's agent and explaining the arrangement or agreement in place.

ERCOT may request additional verification on a case-by-case basis from the relevant Resource Entity in order to verify the DME that controls a Resource. For purposes of this Declaration, "control" is defined as the ultimate decision-making authority over how a Resource is dispatched and priced, either by virtue of ownership or agreement, and a substantial financial stake in the Resource's profitable operation. All Resources under common control are required to declare the same DME.

For a Split Generation Resource, each Resource Entity that owns a portion of the Split Generation Resource shall separately submit this Declaration to identify the DME that controls the associated portion of the Split Generation Resource.

A Resource Entity shall notify ERCOT of any known changes in its Resource's DME no later than 14 calendar days prior to the date that the change takes effect, or as soon as possible in a situation where the Resource Entity cannot meet the 14 calendar day notice requirement. However, in no event may the Resource Entity inform ERCOT later than 72 hours before the date on which the change in DME takes effect. In addition, this Managed Capacity Declaration form must be submitted and accepted by ERCOT before these changes are applied to the associated Resource(s).

The signed Declaration form may be submitted electronically through the Market Information System (MIS) located at https://mis.ercot.com/pps/tibco/mis as a Service Request, using the Type: MP Registration and Sub-Type: Resource/Asset Registration. Submission through the MIS link requires a valid Authorized Representative's Digital Certificate. An alternative to MIS is to submit the signed Declaration form in pdf format to both ercotregistration@ercot.com and MPRegistration@ercot.com.

If questions arise related to the completion of this form, please contact your designated ERCOT Account Manager or email ERCOT Client Services at ClientServices@ercot.com with the subject "Decision-Making Entity Form".

Declaration of Decision-Making Entity ("DME")

Resource Entity	
DUNS Number	

Resource Site Name	**Resource Unit Code, as Registered with ERCOT**	**DME [If DME is currently listed in the Resource Control Report, use name as listed]**	**DME DUNS Number [If new DME, leave blank]**

To view the current registered DME list, open the most recent csv from the Resource_Control_Report.

Authorized Representative indicated and signed below attests that all statements made and information provided in this Declaration are true, correct and complete.

Signature: ____
(Authorized Representative signature)

Printed Name: ____
(Authorized Representative)

Date: ____________________

ERCOT Nodal Protocols

Section 23

Form D: Market Participant Agency Agreement

February 1, 2022

Market Participant Agency Agreement

This Market Participant Agency Agreement (“Agreement”) effective as of Date (“Effective Date”) is entered into by and among Name of Agent, a Business Entity & Type (“Agent”) and Name of Principal, a Business Entity & Type (“Principal”) and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation (“ERCOT”).

In consideration of the mutual covenants and promises contained herein, the parties to this Agreement hereby agree as follows:

1. “ERCOT Protocols” shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and settlement (including customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. Definitions contained in the ERCOT Protocols shall apply to this Agreement.
2. Principal is a *(mark all Entity types that apply)*: ☐ Transmission Service Provider
   ☐ Distribution Service Provider
   ☐ Resource Entity
   ☐ Load Serving Entity
3. Principal agrees that Agent has the authority to act on Principal’s behalf for any activity governed by the ERCOT Protocols and agrees to be bound by Agent’s acts as if Principal had performed such acts.
4. Agent agrees to perform on Principal’s behalf, or coordinate with Principal for the performance of, all actions that are required of Principal under the ERCOT Protocols.
5. With respect to any activity that would be required of Principal under the ERCOT Protocols, ERCOT agrees to communicate with Agent and to allow Agent’s performance of such activity on behalf of Principal.
6. Agent represents and warrants that it has executed or will timely execute and maintain any agreements required by the ERCOT Protocols of Agent acting on its own behalf. Agent further represents and warrants that it has executed or will timely execute and maintain any agreements required by the ERCOT Protocols of Principal (i.e. for all Entity types marked above). Agent and Principal further agree that, during the term of this Agreement, Agent may act on behalf of Principal under such agreements as though Principal had executed such agreements.
7. This Agreement is effective as of the Effective Date and may be terminated by any party upon 30 days written notice to all other parties.
8. Notices under this Agreement shall be delivered to the parties at the addresses specified below in accordance with the notice procedures set forth in the Standard Form Market Participant Agreement (Section 22, Attachment A).

Each person whose signature appears below represents and warrants that he or she has authority to bind the party on whose behalf he or she has executed this Agreement. Executed and Agreed:

ERCOT: Signed: ________________________ Printed Name: ___________________ Position/Title: ___________________ Date: __________________________ Address: 8000 Metropolis Drive (Building E), Suite 100 Austin, Texas 78744	Agent: Signed: ________________________ Printed Name: Name Position/Title: Title Date: Date Address: Street Address City, State, Zip	Principal: Signed: ________________________ Printed Name: Name Position/Title: Title Date: Date Address: Street Address City, State, Zip

ERCOT Nodal Protocols

Section 23

Form E: Notice of Change of Information

February 1, 2022

NOTICE OF CHANGE OF INFORMATION

A Market Participant must update, amend and/or correct the registration information previously submitted to ERCOT using this Notice of Change of Information (NCI). The Market Participant must notify ERCOT of any change to the information or additional information on any application or form that it has previously submitted to ERCOT according to the notification timeframe in the ERCOT Protocols or, if the Protocols do not contain a timeframe for the subject matters, at least 30 days before the change will take effect. Please fill out this form electronically, print and execute. Submit all changes and/or additional information by one of the following methods: 1) Market Information System (MIS); 2) email to MPRegistration@ercot.com; 3) facsimile to (512) 225-7079; or 4) regular mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744.

Except as otherwise required by the ERCOT Protocols, ERCOT will send a written acknowledgement of receipt of the changes within five Business Days of receipt and will notify Market Participant of any deficiencies or any additional documentation required within 10 days of receipt. The notice of receipt will be sent to the email address of the Authorized Representative on file with ERCOT or the address specified in the NCI received by ERCOT.

The following contacts/information can be changed via the submittal of this NCI:

- **Authorized Representative (“AR”)** – Responsible for updating all registration information, and will be the contact person between the Market Participant and ERCOT for all business matters requiring authorization by ERCOT. *(All Market Participant Types)*

- **Backup AR** – May perform the functions of the AR in the event the AR is unavailable. *(All Market Participant Types)*

- **User Security Administrator (USA)** – Responsible for managing the Market Participant’s access to ERCOT’s computer systems through Digital Certificates. *(All Market Participant Types)*

- **Backup USA** – May perform the functions of the USA in the event the USA is unavailable. *(All Market Participant Types)*

- **Cybersecurity** – Responsible for communicating Cybersecurity Incidents.

- **24x7 Control or Operations Center (24x7)** – Responsible for operational communications. Shall have sufficient authority to commit and bind the entity. The Market Participant must provide a 24x7 phone number for the operations desk in a manner that reasonably assures continuous communication with ERCOT and is not affected by private branch exchange (PBX) features such as automatic transfer or roll to voice mail. *(Qualified Scheduling Entities (QSEs), sub-QSEs, Transmission Service Providers (TSPs))*

- **Compliance** – Responsible for compliance related issues. *(QSEs, Sub-QSEs, Resource Entities (“REs”), TSPs, Distribution Service Providers (DSPs))*

- **Accounts Payable (“AP”)** – Responsible for settlements and billing. *(Congestion Revenue Right (CRR) Account Holders (CRRAHs), QSEs, Sub-QSEs)*

- **Backup AP** – May perform the functions of the AP in the event the AP is unavailable. *(CRRAHs, QSEs, Sub-QSEs)*

- **Credit** – Responsible for all credit-related matters. *(Counter-Parties (CPs))*

- **Backup Credit** – May perform the functions of the Credit in the event the Credit is unavailable. *(CPs)*

- **Transition/Acquisition (“TA”)** – Requirement for Competitive Retailers (CRs) and Transmission and/or Distribution Service Providers (TDSPs). Responsible for coordinating Mass TA events between ERCOT, TDSPs and CRs. The CR may be a Provider of Last Resort (POLR), Designated CR, Gaining CR or Losing CR. Includes TA Business (“TAB”), TA Regulatory (“TAR”) and TA Technical (“TAT”). List one contact per TA. *(Load Serving Entities (LSEs), TSPs, DSPs)*

- **Legal Address Change** *(All Market Participant Types)*

Received:

*Market Participant Account Name(s):	
*Data Universal Numbering System (DUNS) Number(s):	
*Market Participant Type(s):	☐ CP ☐ CRRAH ☐ Independent Market Information System Registered Entity (IMRE) ☐ LSE ☐ QSE/Sub-QSE ☐ RE ☐ TSP and/or DSP

Comments (if necessary): _____

*AR, Backup AR or Officer:	
*Signature:	
*Email:	
*Phone Number:	

1. Contact type(s): ☐ AR ☐ Backup AR ☐ USA ☐ Backup USA ☐ Cybersecurity ☐ 24x7 ☐ Compliance ☐ AP ☐ Backup AP ☐ Credit ☐ Backup Credit ☐ TAB ☐ TAR ☐ TAT

Name:		Title:			
Address:					
City:		State:		Zip:	
Telephone:		Fax:			
Email Address:					

If former contact(s) is/are no longer with the Market Participant please list name(s) here: _____

Contact type(s): ☐ AR ☐ Backup AR ☐ USA ☐ Backup USA ☐ Cybersecurity ☐ 24x7 ☐ Compliance ☐ AP ☐ Backup AP ☐ Credit ☐ Backup Credit ☐ TAB ☐ TAR ☐ TAT

Name:		Title:			
Address:					
City:		State:		Zip:	
Telephone:		Fax:			
Email Address:					

If former contact(s) is/are no longer with the Market Participant please list name(s) here: _____

Contact type(s): ☐ AR ☐ Backup AR ☐ USA ☐ Backup USA ☐ Cybersecurity ☐ 24x7 ☐ Compliance ☐ AP ☐ Backup AP ☐ Credit ☐ Backup Credit ☐ TAB ☐ TAR ☐ TAT

Name:		Title:			
Address:					
City:		State:		Zip:	

Telephone:		Fax:	
Email Address:			

If former contact(s) is/are no longer with the Market Participant please list name(s) here: _____

Contact type(s): ☐ AR ☐ Backup AR ☐ USA ☐ Backup USA ☐ Cybersecurity ☐ 24x7
☐ Compliance ☐ AP ☐ Backup AP ☐ Credit ☐ Backup Credit ☐ TAB ☐ TAR
☐ TAT

Name:		Title:			
Address:					
City:		State:		Zip:	
Telephone:		Fax:			
Email Address:					

If former contact(s) is/are no longer with the Market Participant please list name(s) here: _____

Contact type(s): ☐ AR ☐ Backup AR ☐ USA ☐ Backup USA ☐ Cybersecurity ☐ 24x7
☐ Compliance ☐ AP ☐ Backup AP ☐ Credit ☐ Backup Credit ☐ TAB ☐ TAR
☐ TAT

Name:		Title:			
Address:					
City:		State:		Zip:	
Telephone:		Fax:			
Email Address:					

If former contact(s) is/are no longer with the Market Participant please list name(s) here: _____

Contact type(s): ☐ AR ☐ Backup AR ☐ USA ☐ Backup USA ☐ Cybersecurity ☐ 24x7
☐ Compliance ☐ AP ☐ Backup AP ☐ Credit ☐ Backup Credit ☐ TAB ☐ TAR
☐ TAT

Name:		Title:			
Address:					
City:		State:		Zip:	
Telephone:		Fax:			
Email Address:					

If former contact(s) is/are no longer with the Market Participant please list name(s) here: _____

Contact type(s): ☐ AR ☐ Backup AR ☐ USA ☐ Backup USA ☐ Cybersecurity ☐ 24x7
☐ Compliance ☐ AP ☐ Backup AP ☐ Credit ☐ Backup Credit ☐ TAB ☐ TAR
☐ TAT

Name:		Title:			
Address:					
City:		State:		Zip:	
Telephone:		Fax:			
Email Address:					

If former contact(s) is/are no longer with the Market Participant please list name(s) here: _____

2. Legal Address Change

Address:

City, State, Zip:

3. Cancelation of User Security Administrator (USA) and Digital Certificate Opt-Out

☐ By checking this box, Market Participant elects to: (i) cancel its USA and Digital Certificate Opt-Out; (ii) designate a USA and optionally a Backup USA, listed in Section 1, Contact type(s), of this NCI form; and (iii) receive Digital Certificates as required by Section 16.12, User Security Administrator and Digital Certificates. Market Participant understands that designation of a USA and Backup USA, and issuance of Digital Certificates, is subject to the requirements in Section 16.12.

ERCOT Nodal Protocols

Section 23

Form F: Qualified Scheduling Entity (QSE) Agency Agreement

February 1, 2022

QUALIFIED SCHEDULING ENTITY (QSE) AGENCY AGREEMENT

This Qualified Scheduling Entity (QSE) Agency Agreement (“Agreement”) is made this Day of Month day of Month, Year (“Effective Date”) by and between Electric Reliability Council of Texas, Inc. (“ERCOT”), Name of Principal (“Principal”), and Name of Agent (“Agent”).

WHEREAS, ERCOT is the Independent Organization certified under Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2007) (PURA) for the ERCOT Region, and

WHEREAS, Principal has a valid Standard Form Market Participant Agreement (Section 22, Attachment A) with ERCOT, is registered as a QSE with ERCOT, and has contracted with Agent to provide QSE support services to Principal, and

WHEREAS, Agent has a valid Standard Form Market Participant Agreement (Section 22, Attachment A) with ERCOT, is registered as a QSE with ERCOT, and is subject to all ERCOT Protocols as an authorized QSE, and

WHEREAS, the three parties to this Agreement desire a clear expression of their rights, obligations, and privileges with respect to their inter-related conduct under the ERCOT Protocols.

NOW THEREFORE, the parties do hereby agree as follows:

1. “ERCOT Protocols” shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, procedures, standards, and criteria of ERCOT. Definitions contained in the ERCOT Protocols shall apply to this Agreement.

2. Principal does hereby appoint Agent as its authorized agent for the limited purpose of (select one or more of the following):

   ☐ A. Communicating with and receiving operational voice communications from ERCOT over the ERCOT Wide Area Network (WAN), including, without limitation, receiving and discussing Dispatch Instructions;

   ☐ B. Exchanging Inter-Control Center Communications Protocol (ICCP) data with ERCOT over the ERCOT WAN; and/or

   ☐ C. Exchanging Extensible Markup Language (XML) data with ERCOT over the ERCOT WAN.

3. Agent does hereby accept the appointment as the limited agent for Principal, solely for the purposes described in paragraph 2, above.

4. ERCOT acknowledges the existence of a separate service contract between Principal and Agent, as well as the limited agency appointment contained in this Agreement, which from time to time will result in Agent-to-ERCOT communications on Principal's behalf.

5. ERCOT grants Principal and Agent the privilege of enjoying such an agency relationship by permitting direct Agent communications to and from ERCOT on Principal's behalf for the purposes described in paragraph 2, above, without requiring an express authorization from Principal for each such communication.

6. Principal and Agent agree to abide by all ERCOT Protocols, as amended from time to time.

7. Principal and Agent do hereby release ERCOT of any liability for the revealing, transmitting, or publishing to Agent of any sensitive Principal commercial and operational data or Principal's Protected Information.

8. Principal and Agent agree that this Agreement governs QSE support services for only the QSE and/or sub-QSEs designated herein:

Name of QSE	DUNS Number
Name of Sub-QSE	DUNS Number
Name of Sub-QSE	DUNS Number
Name of Sub-QSE	DUNS Number
Name of Sub-QSE	DUNS Number

9. This Agreement shall terminate no later than Termination Date. Any party to this Agreement may terminate it upon thirty days advance written notice to the other parties. Notice of termination of this Agreement shall be provided to the address listed herein in accordance with the notice provisions contained in the parties' respective Standard Form Market Participant Agreements.

Executed and agreed as of the Effective Date by the below named authorized signatories:

Principal:	Agent:	ERCOT:
Signed:	Signed:	Signed:
______________________	______________________	______________________
Printed Name: Name	Printed Name: Name	Printed Name: Name
Position/Title: Title	Position/Title: Title	Position/Title: Title
Date: Date	Date: Date	Date: Date
Address: Address City, State, Zip	Address: Address City, State, Zip	Address: 8000 Metropolis Drive (Building E), Suite 100 Austin, Texas 78744

ERCOT Nodal Protocols

Section 23

Form G: QSE Application and Service Filing for Registration Form

December 1, 2022

QUALIFIED SCHEDULING ENTITY (QSE) APPLICATION AND SERVICE FILING FOR REGISTRATION

This application is for approval as a Qualified Scheduling Entity (QSE) by 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), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. In addition to the application, ERCOT must receive an application fee in the amount of $500 via check. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application 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.

☐ **Check if Applying as an Emergency Response Service (ERS) Only QSE.**

1. Authorized Representative (“AR”). Defined in Section 2.1, Definitions.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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 as defined in the ERCOT Protocols in the event the AR is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual
☐ Electric Cooperative
☐ Other: _____
☐ Partnership
☐ Limited Liability Company
☐ Municipally Owned Utility
☐ Corporation

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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

7. Control or Operations Center. As defined in item (1)(k) and (1)(l) of Section 16.2.1, Criteria for Qualification as a Qualified Scheduling Entity, the control or operations center is responsible for operational communications and shall have sufficient authority to commit and bind the QSE. For QSE Level 2, 3, and 4 the availability of the control or operations center is 24-hour, seven-day-per-week. For QSE Level 1 the availability of the control or operations center is during the hours of 0900 to 1700 Central Prevailing Time (CPT) on Business Days.

Desk Name:					
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			

Email Address:	

8. Compliance Contact. This person is responsible for compliance related issues.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

9. Proposed commencement date for service: _____

PART II – BANKING INFORMATION FOR FUNDS TRANSFERS

1. Banking Information. Applicant must be able to conduct Electronic Funds Transfers (EFTs) for the settlement of financial transactions with ERCOT.

Bank Name:	
Account Name:	
Account No.:	
ABA Number:	

2. Accounts Payable Contact (Settlement & Billing).

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Backup Accounts Payable Contact (Settlement & Billing). *(Optional)*

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

PART III – DECLARATION OF SUBORDINATE QSEs

If the QSE intends to partition itself into subordinate QSEs (Sub-QSEs), please enter information for each Sub-QSE below. If a Sub-QSE will have a different Contact than the QSE, please provide that information in the spaces provided below. The Sub-QSE name must have a reference to the Legal Entity Name. For example: Legal Name of Market Participant (SQ1), Legal Name of Market Participant (SQ2), etc.

Sub-QSE One (SQ1)
Name: **Proposed commencement date for service:**
Contact information same? ☐ **Yes** ☐ **No (If no, complete the section below)**

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Sub-QSE Two (SQ2)
Name: **Proposed commencement date for service:**
Contact information same? ☐ **Yes** ☐ **No (If no, complete the section below)**

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Sub-QSE Three (SQ3)
Name: **Proposed commencement date for service:**
Contact information same? ☐ **Yes** ☐ **No (If no, complete the section below)**

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

Sub-QSE Four (SQ4)
Name: **Proposed commencement date for service:**
Contact information same? ☐ **Yes** ☐ **No (If no, complete the section below)**

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

PART IV – ADDITIONAL REQUIRED INFORMATION

1. Officers and Principals. Provide the name of all officers and the name and position of each Principal, as defined by Section 16.1.2, Principal of a Market Participant. In addition, ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State 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, 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.)*

3. Disclosures. Provide the name of any Principal of the Applicant that is now, or was at any point in time, a Principal of any other Entity that is now, or was at any point in time, a registered ERCOT Market Participant, along with the name of the relevant ERCOT Market Participant and the dates during which the Principal of the Applicant was a Principal of the other Entity.

4. Counter-Party Credit Application. Complete the Counter-Party Credit Application, located at http://www.ercot.com/services/rq/credit, and submit as instructed in conjunction with this application, in accordance with Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

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.)

5. Annual Certification Form to Meet ERCOT Additional Minimum Participation. Complete Section 22, Attachment J, Annual Certification Form to Meet ERCOT Additional Minimum

Participation Requirements, and submit in conjunction with this application, pursuant to Section 16.16.3, Verification of Risk Management Framework.

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:	

ERCOT Nodal Protocols

Section 23

Form H: QSE Acknowledgement

November 1, 2017

QSE Acknowledgment

Acknowledgment by Designated QSE for Scheduling and Settlement Responsibilities with ERCOT

The Market Participant below has named the Qualified Scheduling Entity (QSE) listed below as its designated QSE to represent the Market Participant for scheduling and Settlement transactions with ERCOT.

The Market Participant's designated QSE, listed below, hereby acknowledges that it does represent the Market Participant and that it shall be responsible for the Market Participant'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 Authorized Representative ("AR") for QSE:	
Printed Name of AR:	
Email Address of AR:	
Date:	
Name of Designated QSE:	
DUNS of Designated QSE:	

Acknowledgment by **Market Participant**:

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 Nodal Protocols

Section 23

Form I: Resource Entity Application for Registration

February 1, 2022

RESOURCE ENTITY
APPLICATION FOR REGISTRATION

This application is for approval as a Resource Entity 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. The completed, executed application will be accepted by ERCOT via email to MPRegistration@ercot.com (.pdf version), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application 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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual
☐ Electric Cooperative
☐ Other: _____
☐ Partnership
☐ Limited Liability Company
☐ Municipally Owned Utility
☐ Corporation

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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

7. Compliance Contact. This person is responsible for compliance related issues.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

8. Proposed commencement date for service: _____.

PART II – ADDITIONAL REQUIRED INFORMATION

1. Officers. ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State 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, 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.)*

3. Qualified Scheduling Entity (QSE) Acknowledgment. Provide all information requested in Attachment A and have the document executed by both parties. Resource Entities representing Generation Resources or Load Resources shall designate a QSE qualified to represent the Resources. Resource Entities with Settlement Only Generators (SOGs) shall designate any qualified QSE.

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 III – 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 Authorized Representative ("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.*

[NPRR995: Replace Section 23, Form I above with the following upon system implementation:]

RESOURCE ENTITY
APPLICATION FOR REGISTRATION

This application is for approval as a Resource Entity 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. The completed, executed application will be accepted by ERCOT via email to MPRegistration@ercot.com (.pdf version), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application 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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual
☐ Electric Cooperative
☐ Other: _____

☐ Partnership
☐ Limited Liability Company

☐ Municipally Owned Utility
☐ Corporation

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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

7. Compliance Contact. This person is responsible for compliance related issues.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			

Email Address:	

8. Proposed commencement date for service: _____.

PART II – ADDITIONAL REQUIRED INFORMATION

1. Officers. ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State 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, 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.)*

3. Qualified Scheduling Entity (QSE) Acknowledgment. Provide all information requested in Attachment A and have the document executed by both parties. Resource Entities representing Generation Resources or Load Resources shall designate a QSE qualified to represent the Resources. Resource Entities with Settlement Only Generators (SOGs) or Settlement Only Energy Storage Systems (SOESSs) shall designate any qualified QSE.

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 III – 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 Authorized Representative ("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 Nodal Protocols

Section 23

Form J: Transmission and/or Distribution Service Provider Application for Registration

February 1, 2022

Date Received: ______________________

TRANSMISSION AND/OR DISTRIBUTION SERVICE PROVIDER (TDSP) APPLICATION FOR REGISTRATION

This application is for approval as a Transmission Service Provider (TSP), Distribution Service Provider (DSP), or both TSP and DSP by 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), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application must be signed by the Authorized Representative ("AR"), 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 – COMPANY 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.

Type: TSP ☐ DSP ☐ Both ☐ as reflected on Standard Form Agreement

1. Authorized Representative ("AR"). Defined in Section 2.1, Definitions.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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 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.

(e) If determined ineligible, Applicant must designate a USA, receive Digital Certificates and comply with requirements under Protocol Section 16.12.

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:			**Title:**		
Address:					
City:		**State:**		**Zip:**	
Telephone:			**Fax:**		
Email Address:					

7. TSP 24x7 Control or Operations Center. As defined in the ERCOT Protocols, the 24x7 Control or Operations Center is responsible for operational communications and shall have sufficient authority to commit and bind the TSP.

Desk Name:					
Address:					
City:		**State:**		**Zip:**	
Telephone:			**Fax:**		
Email Address:					

8. Compliance Contact. This person is responsible for compliance related issues.

Name:			**Title:**		
Address:					
City:		**State:**		**Zip:**	
Telephone:			**Fax:**		
Email Address:					

PART II – ASSET REGISTRATION

1. Provide Generation Load Metering Point and TDSP Read Generation information as required on the ERCOT Generation Load Metering Point(s) & TDSP Read Generation Registration Form. The form is located at http://www.ercot.com/services/rq/tdsp/index.html. The completed form should be attached to, and submitted with, the TDSP Registration Application.

2. Provide status of registering MOU or EC:

☐ **Opt-In MOU or EC** – An EC or MOU that offers Customer Choice.

☐ **Non-Opt-In Entity (NOIE)** – An EC or MOU that does not offer Customer Choice.

PART III – ADDITIONAL REQUIRED INFORMATION

1. Officers. ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State 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 IV – 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:	

ERCOT Nodal Protocols

Section 23

Form K: Wide Area Network (WAN) Agreement

February 1, 2022

ERCOT Private Wide Area Network (WAN) Agreement

This Private WAN Agreement ("Agreement") is made and entered into on this day of , ("Effective Date") by and between Electric Reliability Council of Texas, Inc. (ERCOT), a Texas non-profit corporation having an office at 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744 and the undersigned entity ("Participant") (collectively, "the Parties"), having an office at the address listed below.

1. Scope

1.1 This Agreement sets forth the terms, conditions and prices under which ERCOT agrees to allow Participant to interconnect Participant's data transfer system with ERCOT's data network and facilities for the sole purpose of transferring data between ERCOT and Participant. This Agreement also sets forth the terms and conditions to maintain operational security of the ERCOT WAN for the secure transfer of data between ERCOT and Participant.

1.2 Participant represents and warrants that Participant is a Market Participant as defined by the ERCOT Protocols and has executed (or will timely execute prior to participation as a Market Participant) all agreements required of Participant by the ERCOT Protocols (Protocols Agreement(s)). This Agreement shall terminate immediately and automatically upon the termination of all Participant's Protocols Agreement(s). "ERCOT Protocols" shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time that contains the scheduling, operating, planning, reliability, and settlement (including customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT.

1.3 Except to the extent provided otherwise in this Agreement, the terms and conditions of the Protocols Agreement(s) signed between Participant and ERCOT shall apply and be incorporated by reference into this Agreement. In the event of a conflict between this Agreement and the Protocols Agreement(s), this Agreement shall control with respect to the subject matter of this Agreement.

2. Term of Agreement

2.1 The initial term of this Agreement shall commence on the Effective Date and expire 12 months thereafter. The term of this Agreement shall automatically renew for a successive 12-month period on each anniversary date of the Effective Date, unless either party delivers to the other party written notice to terminate as provided herein.

2.2 If Participant wishes to terminate this Agreement, it shall notify ERCOT in writing of its desire to terminate. Termination shall be effective no sooner than 60 days following receipt of such written notice by ERCOT.

2.3 In addition to any other remedies ERCOT may have at law or in equity, ERCOT may terminate this Agreement for material breach in accordance with the default provisions set forth in the Protocols Agreement(s).

2.4 ERCOT may also terminate this Agreement upon 60 days' written notice to Participant if ERCOT amends the form of this standard form agreement. In such event, ERCOT shall provide Participant the opportunity to execute a new standard form agreement regarding the subject matter of this Agreement.

2.5 In the event of any termination of this Agreement, Participant shall reimburse ERCOT for ERCOT's expenses incurred hereunder prior to notice of termination. If this Agreement has been terminated except as proved under Section 2.4 above, ERCOT may remove from Participant's premises any equipment for which ERCOT has not received payment and Participant shall reimburse ERCOT for the cost of such removal.

3. Interconnection with and use of ERCOT WAN

3.1 Participant shall interconnect its facilities with ERCOT in a manner consistent with and defined by ERCOT. ERCOT shall define and demarcate the location of interconnection with the ERCOT WAN.

3.2 ERCOT shall provide, in accordance with its reasonable discretion and control, the design, engineering, procurement, and installation of the equipment and facilities necessary to interconnect Participant's Facilities to the ERCOT WAN. Participant shall reimburse ERCOT for ERCOT's expenses incurred in design, engineering, procurement, and installation of such equipment and facilities for each such new installation. The reimbursed costs for each new installation shall not exceed the fees designated in the ERCOT Fee Schedule. Only ERCOT-authorized personnel shall conduct network problem diagnosis and administrative functions, including, but not limited to, provisioning, monitoring, and auditing the ERCOT WAN. Participant will reimburse ERCOT's cost of performing or acquiring such services per month per installation during the initial term hereof and any subsequent renewal terms. The monthly cost per installation shall not exceed the fees designated in the ERCOT Fee Schedule. Participant will also reimburse ERCOT's cost of providing or acquiring data transport service to Participant, which cost will vary according to Participant's location.

3.3 With respect to access to the ERCOT WAN, Participant will comply with ERCOT's security and safety procedures and requirements, including, but not limited to, access restrictions, sign in, and identification requirements. Participant will also comply with all ERCOT policies and procedures regarding use of the ERCOT WAN (as such policies and procedures may be amended from time to time), including, but not limited to, the document entitled "Communicating with ERCOT," the document entitled "QSE Qualification Testing," the ERCOT Operating Guides and ERCOT Protocols.

3.4 Participant shall consistently maintain the security of its computer systems (including the interconnection with the ERCOT WAN, support equipment, systems, tools, and/or data required under this Agreement) in accordance with industry standards for computer system security.

3.5 Participant shall maintain operational security of the ERCOT WAN for the uninterrupted transfer of data between ERCOT and Participant. Participant agrees that the integrity of the data provided through the WAN is essential, and will take all steps and responsibility for ensuring the integrity of such data. Such steps shall include, at a minimum, ensuring the prevention of any remote electronic connections by unauthorized persons or organizations through Participant's network to the ERCOT WAN connection point. Particularly, Participant's systems must deny any connectivity with Participant's internet access point to unauthorized persons or organizations.

3.6 If ERCOT determines, within its reasonable discretion, that Participant is not in compliance with this Agreement or ERCOT's security procedures and requirements, ERCOT may prohibit Participant from transferring data using the WAN.

3.7 Where one Party's information resides on the other Party's computer system, the Party in control of the computer system shall take, or cause the custodian of the computer system to take commercially reasonable measures to prevent unauthorized access to such information by others who have access to that computer system. Each Party agrees that it, its employees, agents and representatives who have access to its computer systems at its facilities will not use the WAN and/or the interconnection with the ERCOT WAN to obtain or to attempt to obtain unauthorized access to information of the other Party or information of a third party that may reside on the other Party's computer system.

4. Network Maintenance and Management

4.1 As part of the WAN Application, Participant has provided ERCOT contact information for network maintenance and management. Participant may change such contact information by submitting a Notice of Change of Information (NCI) (Section 23, Form E) to ERCOT, and referring specifically to this Agreement.

4.2 Participant will not use any service provided under this Agreement in a manner that impairs the quality of service to other WAN users. Participant shall cooperate with ERCOT in the testing of interconnection to the WAN and in the prevention or correction of disruption or loss of service over the WAN.

4.3 ERCOT agrees to provide Participant reasonable written notice of changes in the information necessary for the transmission and routing of data using ERCOT's facilities or networks, as well as other changes that affect the interoperability of those respective facilities and networks.

4.4 Participant agrees to notify the ERCOT Help Desk immediately of any intrusion or virus event within its network or systems connected to the ERCOT WAN so that ERCOT can take steps to ensure the integrity of the rest of the WAN.

5. Compensation

5.1 Participant agrees to reimburse ERCOT for ERCOT's expenses incurred in the design, engineering, procurement, and installation of equipment and facilities hereunder. Participant further agrees to pay ERCOT for any additional services rendered by ERCOT under this Agreement; to the extent such expenses and chargers are assessed pursuant to Section 3.2 above.

5.2 ERCOT will remit a bill to Participant to reflect the charges required and permitted pursuant to Section 3.2 above under this Agreement, any applicable taxes, and other costs or charges that are the responsibility of Participant, but were incurred by ERCOT. Payment is due within 30 days of receipt of the bill.

5.3 Payments shall be made either through bank draft or wire transfer, as agreed upon by the parties. Interest shall accrue on any past due amount at the lesser of: (a) 18% per annum; or (b) the maximum rate permitted by applicable law. If Participant fails to make payment within 30 days of receipt of the bill, ERCOT may, at its option, terminate this Agreement.

6. Liability

6.1 EXCEPT TO THE EXTENT REQUIRED BY STATE OR FEDERAL LAW, ERCOT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO ANY WARRANTY AS TO MERCHANT ABILITY OR FITNESS FOR INTENDED OR PARTICULAR PURPOSE WITH RESPECT TO EQUIPMENT OR SERVICES PROVIDED HEREUNDER. ADDITIONALLY, ERCOT MAKES NO WARRANTIES, EXPRESS OR IMPLIED, CONCERNING PARTICIPANT'S (OR ANY THIRD PARTY'S) RIGHTS WITH RESPECT TO INTELLECTUAL PROPERTY OR THIRD PARTY CONTRACT RIGHTS, INCLUDING WHETHER SUCH RIGHTS WILL BE VIOLATED BY PARTICIPANT'S INTERCONNECTION WITH ERCOT'S WAN OR PARTICIPANT'S USE OF THE OTHER EQUIPMENT OR FACILITIES FURNISHED UNDER THIS AGREEMENT.

6.2 Each Party understands and acknowledges that third parties might obtain unauthorized remote access to the other Party's computer systems, and further, that there exists the possibility that such third parties may attempt unauthorized access to the computer systems or information thereon, that computer viruses may be transmitted, and that damage might result to a Party's computer systems or data thereon, or that the confidentiality of a Party's information may thereby be breached. ACCORDINGLY, EACH PARTY SHALL BE SOLELY AND EXCLUSIVELY RESPONSIBLE FOR SAFEGUARDING ITS OWN COMPUTER SYSTEMS AND INFORMATION THEREON FROM SUCH UNAUTHORIZED ACCESS OR DAMAGE OCCURRING THROUGH THE INTERCONNECTION WITH ERCOT UNDER THIS AGREEMENT AND FOR THE ACTIONS OF ITS EMPLOYEES, AGENTS, AND REPRESENTATIVES WHO USE ITS COMPUTER SYSTEMS.

7. Notices

Except as provided herein for operational communications, all notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three days after being deposited in the U.S. mail, first class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or Federal Express delivery. ERCOT may change its address for such notices by delivering to Participant a written notice referring specifically to this Agreement. Participant may change its address for such notices by submitting an NCI (Section 23, Form E) to ERCOT and referring specifically to this Agreement.

8. Entire Agreement and Amendments

8.1 This Agreement constitutes the entire agreement between the Parties concerning the subject matter hereof and supersedes any prior agreements, representations, statements, negotiations, understandings, proposals or undertakings, oral or written, with respect to the subject matter expressly set forth herein.

8.2 Neither Party will be bound by an amendment, modification or additional term unless it is reduced to writing and signed by an authorized representative of the Party sought to be bound.

Each person whose signature appears below represents and warrants that he or she has authority to bind the Party on whose behalf he or she has executed this Agreement.

Executed and Agreed:

Electric Reliability Council of Texas, Inc.:	Participant:
Signature: ____________________________	Signature: ____________________________
Date: ________________________________	Date: Printed Name:
Printed Name: _________________________	Title: Address:
Title: ________________________________	City, State, Zip:
8000 Metropolis Drive (Building E), Suite 100 Austin, Texas 78744 (512) 225-7000	Type of Organization: Organized Under the Laws of:

ERCOT Nodal Protocols

Section 23

Form L: Digital Certificate Audit Attestation

February 1, 2022

Digital Certificate Audit Attestation

Pursuant to Section 16.12.3, Market Participant Audits of User Security Administrators and Digital Certificates, each Market Participant must verify compliance with the Digital Certificate use requirements set forth in the ERCOT Protocols. Market Participants must complete this form and return it via (i) email to DCAA@ercot.com (.pdf version); or (ii) regular mail to: ERCOT, Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. This audit and attestation shall be completed for *each* DUNS Number the Market Participant has currently registered with ERCOT.

Legal Name of the Market Participant:	
Market Participant Type:	☐ **CP** ☐ **CRRAH** ☐ **IMRE** ☐ **LSE** ☐ **QSE** ☐ **Sub-QSE** ☐ **Resource** ☐ **TSP and/or DSP**
DUNS Number:	
User Security Administrator (USA):	
Backup USA (if applicable):	

Market Participant hereby affirms the following:

1. Market Participant has generated a list of its registered User Security Administrator (USA), Backup USA, and Digital Certificate holders ("Certificate Holders"), for the DUNS Number indicated above, generated through the Market Participant Identity Management (MPIM) Application within the Market Information System (MIS) (the List), and if Market Participant has any corrections to the List, Market Participant has provided corrections to ERCOT.

2. Market Participant and each listed USA, Backup USA, and Certificate Holder meet the applicable requirements of paragraph (1)(a) of 16.12.1, USA Responsibilities and Qualifications for Digital Certificate Holders.

3. Market Participant and each listed USA, Backup USA, and Certificate Holders are not subject to any of the conditions that would require revocation as described in paragraph (1)(b) of Section 16.12.1.

4. Each listed USA, Backup USA, and Certificate Holder is currently employed by or is an authorized agent contracted with the Market Participant.

5. The Market Participant has verified that the listed USA and Backup USA is authorized to be a USA.

6. Each Certificate Holder is authorized to retain and use the Digital Certificate.

7. Each listed Certificate Holder needs the Digital Certificate to perform his or her job functions.

8. Market Participant has requested revocation of Digital Certificates when required by paragraph (1)(b) of Section 16.12.1.

9. Market Participant has complied with the audit requirements of Section 16.12.3.

Market Participant has found that the following Certificate Holder(s) no longer met the required criteria in paragraph (1)(a) of Section 16.12.1. Market Participant to include: (i) the name of the ineligible Certificate Holder; (ii) reason for ineligibility; and (iii) date upon which Certificate Holder became ineligible.

____

____

____

____

____

____

I affirm that I have personal knowledge of the facts stated in this Digital Certificate Audit Attestation (DCAA) and have the authority to submit this DCAA on behalf of the Market Participant listed above.

<u>Officer/Executive/Employee</u>:

Name and Title:

Signature: ____ **Date:**

ERCOT Nodal Protocols

Section 23

Form M: Independent Market Information System Registered Entity (IMRE) Application for Registration

February 1, 2022

Date Received: ______________________

INDEPENDENT MARKET INFORMATION SYSTEM REGISTERED ENTITY (IMRE) APPLICATION FOR REGISTRATION

This application is for approval as an IMRE 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) or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. In addition to the application, ERCOT must receive an application fee in the amount of $500 via check or wire transfer. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application 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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			

Email Address:	

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual
☐ Electric Cooperative
☐ Other: _____
☐ Partnership
☐ Limited Liability Company
☐ Municipally Owned Utility
☐ Corporation

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:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:		**Title:**			
Address:					
City:		**State:**		**Zip:**	
Telephone:		**Fax:**			
Email Address:					

PART II – 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 (SFA), Amendment to the SFA, Digital Certificate Audit Attestation, 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 III – 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:	

ERCOT Nodal Protocols

Section 23

Form N: Pricing Election for Settlement Only Distribution Generators and Settlement Only Transmission Generators

February 1, 2022

Date Received: ____________________

PRICING ELECTION FOR SETTLEMENT ONLY DISTRIBUTION GENERATORS AND SETTLEMENT ONLY TRANSMISSION GENERATORS

A Resource Entity with a Settlement Only Distribution Generator (SODG) or Settlement Only Transmission Generator (SOTG) may use this form to indicate its election to opt out of nodal pricing for one or more SODGs or SOTGs and to continue receiving Load Zone pricing in accordance with paragraph (5) of Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG), and other related sections. An SODG or SOTG is eligible for Load Zone pricing if, by January 1, 2019, it was either operational or was subject to a Power Purchase or Tolling Agreement (PPA) or Transmission and/or Distribution Service Provider (TDSP) interconnection agreement or had an executed agreement with a developer. If the unit was not operational on or before January 1, 2019, a dated copy of the executed PPA or TDSP interconnection agreement or agreement with a developer must be submitted with this form. This application must be received by ERCOT no later than December 31, 2019.

A Resource Entity representing an SODG or SOTG that has opted out of nodal pricing may also use this form to exercise a one-time irrevocable decision to discontinue receiving Load Zone pricing and to begin receiving applicable nodal pricing. The nodal price will be the price at the Electrical Bus associated with the SODG or SOTG, as described in Section 6.6.3.9.

Load Zone pricing for any SODGs and SOTGs with approved opt-out applications will expire on December 31, 2029. Beginning January 1, 2030, and thenceforth, all SODGs and SOTGs will receive nodal energy pricing.

Information requested below may be inserted electronically to expand the reply spaces for the purpose of submitting an opt-out election for more than one SODG or SOTG, or as otherwise necessary. ERCOT will accept the completed, executed application via email to MPRegistration@ercot.com (.pdf version), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application must be signed by the Authorized Representative (“AR”), Backup AR, or any officer with the authority to bind the Resource Entity. ERCOT may request additional information if necessary.

PART I – RESOURCE REGISTRATION INFORMATION FOR SODG OR SOTG

Indicate the purpose of this submission by checking one:

Opt out of nodal pricing (no later than Dec. 31, 2019)	☐
Discontinue Load Zone pricing (for SODG/SOTG units that previously opted out of nodal pricing)	☐

SODG – Identify the SODG as detailed in its Resource Registration information. If this application is for an SOTG, leave this section blank.

GENCODE	

SOTG – Identify the SOTG as detailed in its Resource Registration information. If this application is for an SODG, leave this section blank.

GENCODE	

Attached Documents. If the SODG or SOTG unit that is the subject of this application was not operational on or before January 1, 2019, the unit will be eligible for nodal opt-out status only if a complete and certified copy of an executed PPA with the unit's Counter-Party, or a complete and certified copy of the TDSP interconnection agreement, or executed agreement with a developer is submitted with this application. The PPA or TDSP interconnection agreement or agreement with a developer must be dated on or before January 1, 2019. *(Attach pages as necessary.)*

PART II – 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 Resource Entity named below. I further affirm that all statements made and information provided in this application form, including any attachments, are true, correct and complete, and that the SODGs and SOTGs identified above are eligible to opt out of nodal pricing under Section 6.6.3.9.

Name of Resource Entity	
Signature of AR, Backup AR or Officer:	
Printed Name of AR, Backup AR or Officer:	
Date:	

ERCOT Nodal Protocols

Section 23

Form O: Notice of Cybersecurity Incident

March 13, 2020

NOTICE OF CYBERSECURITY INCIDENT

A Market Participant shall use this form to notify ERCOT of a Cybersecurity Incident. Market Participant shall fill out this form with as much information as is available upon the time of reporting. Market Participant shall also use this form to provide ERCOT with updated/supplemental information concerning the Cybersecurity Incident as information becomes available.

This Notice of Cybersecurity Incident form shall be submitted to NCSI@ercot.com by the Market Participant's Authorized Representative, Cybersecurity Contact, or an officer of the company. If, as a result of the Cybersecurity Incident, a Market Participant is unable to securely send the Notice of Cybersecurity Incident form to ERCOT, the Market Participant will call the ERCOT HelpDesk at (512) 248-6800 and/or its Client Service Representative to request a secure means for sending the Notice of Cybersecurity Incident to ERCOT.

Market Participant	
Market Participant Account Name(s):	
DUNS Number(s):	
Market Participant Type(s):	☐ CP ☐ CRRAH ☐ IMRE ☐ LSE ☐ QSE/Sub-QSE ☐ RE ☐ TSP and/or DSP
Impacted Market Participant Agent Name(s), *if applicable*:	
Impacted Market Participant Agent Contact Information, *if applicable*:	

Submitter	
Authorized Representative (AR), Backup AR, Cybersecurity Contact, or Officer:	
Signature:	
Email:	
Phone Number:	

Temporary Cybersecurity Contact Information for this Cybersecurity Incident (if different from Cybersecurity Contact information contained in ERCOT's registration files)	
Name:	
Primary Phone:	
Email Address:	

Other:	

Cybersecurity Incident

Details	
Date and Time the Cybersecurity Incident was determined:	
Has the Cybersecurity Incident been resolved?	
Physical location of affected network(s), system(s) &/or application(s):	
Have governmental authorities been notified of the Cybersecurity Incident? If so, please identify the notified entities.	

Description
Provide a description of the Cybersecurity Incident:
Provide a description of the type of information/data that may have been compromised:

Impact/Potential Impacts
To Notifying Market Participant: Check all that apply: ☐ Loss/Compromise of Data ☐ Damage to Systems/Networks/Applications ☐ System/Network/Application Downtime ☐ Other Impacted Systems ☐ Unknown Provide a description of impacts/potential impacts:
To ERCOT: Check all that apply: ☐ Loss/Compromise of Data ☐ Damage to Systems/Networks/Applications ☐ System/Network/Application Downtime ☐ Other Impacted Systems ☐ Unknown

Provide a description of impacts/potential impacts:

To Other Market Participants:

Check all that apply:
☐ Loss/Compromise of Data
☐ Damage to Systems/Networks/Applications
☐ System/Network/Application Downtime
☐ Other Impacted Systems
☐ Unknown

Provide a description of impacts/potential impacts:

Incident Response

Please provide a description of steps that have been taken to remediate the Cybersecurity Incident (e.g., no action taken; system disconnected from network; log files examined; etc.):

Please provide an ongoing log of activities taken during the Cybersecurity Incident response process:

Date	Activity

Additional/Supplemental Information

ERCOT Nodal Protocols

Section 23

Form P: Notice of Change of Banking Information

June 10, 2020

NOTICE OF CHANGE OF BANKING INFORMATION

A Market Participant must update, amend and/or correct banking information previously submitted to ERCOT using this Notice of Change of Banking Information (NCBI) form. Please fill out this form electronically, print, execute, and submit through the Market Information System (MIS) Certified Area. This form may only be executed by the Market Participant’s Authorized Representative (AR), Backup AR, or an Officer of the Market Participant.

Except as otherwise required by the ERCOT Protocols, ERCOT will send a written acknowledgement of receipt of the changes within five Business Days of receipt and will notify Market Participant of any deficiencies or any additional documentation required within 10 days of receipt. The notice of receipt will be sent to the email address of the Authorized Representative on file with ERCOT.

*Market Participant Account Name(s):	
*DUNS Number(s):	
*Market Participant Type(s):	☐ CP ☐ CRRAH ☐ QSE/Sub-QSE

Comments (if necessary): _____

*AR, Backup AR or Officer:	
*Signature:	
*Email:	
*Phone Number:	

Banking Information Change

Bank Name:	
Account Name:	
Account Number:	
ABA Number:	

ERCOT Nodal Protocols

Section 24: Retail Point to Point Communications

January 1, 2021

24 Retail Point to Point Communications

24 RETAIL POINT TO POINT COMMUNICATIONS

Point to point communications include transactions flowing directly between Competitive Retailers (CRs), and Transmission and/or Distribution Service Providers (TDSPs) and do not flow through ERCOT. These point to point transactions may be Customer requested service orders and CR/TDSP invoicing and remittance.

24.1 Maintenance Service Order Request

To initiate an original service order, cancel, or change (update) request, the Competitive Retailer (CR) sends maintenance related information to the Transmission and/or Distribution Service Provider (TDSP) using the 650_01, Service Order Request. The 650_01 transaction sent by the CR shall include a level of information such that the TDSP clearly understands the nature of the request and the work that it is being requested to perform. The TDSP will respond within one Retail Business Day after completion, or attempted completion, of the requested action using the 650_02, Service Order Response, to notify the CR that the service order is either completed, unable to be completed, or rejected, or that a permit is required before the order can be completed. There is a one-to-one relationship between the 650_01 and 650_02 transactions.

24.1.1 Disconnect/Reconnect

Public Utility Commission of Texas (PUCT) Substantive Rules and orders, along with TDSP tariffs, dictate the timeline for both disconnection for non-payment and reconnection after disconnection for non-payment. For more information please refer to the Retail Market Guide Section 7.6, Disconnect and Reconnect for Non-Payment Process.

24.1.2 Suspension of Delivery Service

The following transactions shall be used by a TDSP seeking to suspend delivery service for an Electric Service Identifier (ESI ID).

24.1.2.1 Notification

(1) The 650_04, Planned or Unplanned Outage Notification, is electronically transmitted by the TDSP to the CR to notify the CR of the ESI ID(s) and Service Address(es) affected by either a temporary or permanent suspension of service. The situations under which a 650_04 transaction may be created and transmitted to the CR include:

  (a) An outage has been scheduled by the TDSP for the Customer's Service Address for a specific date and time. This type of suspension may be the result of scheduled tree trimming, electrical inspection, testing, maintenance, or changes/upgrades to network equipment.

  (b) An outage has occurred at the Customer's Service Address, but it was not planned or previously scheduled. Such a suspension is normally needed to remedy a dangerous electrical condition that exists at the Customer's address due to an event or activity such as a fire, meter tampering, or theft of service.

(c) For circumstances when a CR, the Customer, or authorized legal authority (county, city, fire, or police personnel) requests disconnection and meter removal because a structure has been destroyed or demolished, or the TDSP has found the meter removed by an unknown Entity, or has removed the meter for unsafe conditions, the TDSP will send a 650_04 transaction. In events where the CR receives a 650_04 transaction indicating that service to the Premise has been permanently suspended by the TDSP for one of the reasons indicated above, the CR will send an 814_24, Move Out Request, to the TDSP within ten Retail Business Days.

(d) Just like a suspension is scheduled or requested it can also be cancelled. If the suspension request is cancelled for any reason, the TDSP will create a 650_04 transaction indicating that the suspension has been cancelled and send a 650_04 transaction to the CR for every ESI ID that would have been affected by the outage.

(2) To notify the CR of a suspension of delivery service, the TDSP sends Notice to the CR using the 650_04 transaction.

24.1.2.2 Cancellation

To notify the CR of a cancellation of the Notification of suspension of delivery service, the TDSP sends Notice to the CR using the 650_04, Planned or Unplanned Outage, for each ESI ID that would otherwise have been affected by the outage.

24.1.3 Switch Hold Indicator

24.1.3.1 Tampering Switch Hold

(1) A tampering switch hold is used when tampering has been determined to have occurred. A switch hold will be placed on the ESI ID in accordance with P.U.C. SUBST. R. 25.126, Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Been Introduced.

(2) To remove a switch hold indicator, the CR sends the 650_01, Service Order Request, to the TDSP requesting the removal of the switch hold indicator. The TDSP will respond with the 650_02, Service Order Response, to the CR acknowledging receipt of the service order request. Confirmation that the service order request has been completed will be received through the 814_20, ESI ID Maintenance Request.

24.1.3.2 Bill Payment Switch Hold

A bill payment switch hold is used when a Customer has entered into a payment agreement with their current CR. A switch hold will be placed on the ESI ID in accordance with P.U.C. SUBST. R. 25.480, Bill Payment and Adjustments.

(a) To add a switch hold indicator, the CR sends the 650_01, Service Order Request, to the TDSP requesting the addition of the switch hold indicator. The TDSP will respond with the 650_02, Service Order Response, to the CR acknowledging receipt of the service order request. Confirmation that the service order request has been completed will be received through the 814_20, ESI ID Maintenance Request.

(b) To remove a switch hold indicator, the CR sends the 650_01 to the TDSP requesting the removal of the switch hold indicator. The TDSP will respond with the 650_02 response to the CR acknowledging receipt of the service order request. Confirmation that the service order request has been completed will be received through the 814_20 transaction.

24.2 Transmission and/or Distribution Service Provider to Competitive Retailer Invoice

(1) The 810_02, TDSP Invoice, may include monthly delivery charges, discretionary service charges, service order charges, interest credit, and/or late payment charges for the current billing period. Following a positive acknowledgement indicating the transaction passed American National Standards Institute Accredited Standards Committee (ANSI ASC) X12 validation, the Competitive Retailer (CR) shall have five Business Days to send a rejection response in accordance with the Texas Standard Electronic Transaction (TX SET) Implementation Guides posted on the ERCOT website and Public Utility Commission of Texas (PUCT) Substantive Rules. If the CR has not received a response transaction to an enrollment or move in, the CR shall not reject the invoice, but will utilize an approved market process (MarkeTrak or dispute process) to resolve the issue. Details of these processes may be found in the Retail Market Guide Section 7, Market Processes.

(2) Only one 810_02 transaction may be sent for a single service period, however, any additional 810_02 transaction for the same Electric Service Identifier (ESI ID) may be sent for a late payment charge after the 35th calendar day for an unpaid 810_02 transaction or for interest credit.

(3) The 810_02 may be paired with an 867_03, Monthly or Final Usage, to trigger the Customer billing process.

(4) The Transmission and/or Distribution Service Provider (TDSP) may cancel and replace (rebill) the original 810_02 transaction. The values in the cancel transaction will be identical in amounts to what they were on the original invoice. The replacement (rebilled) invoice now becomes the monthly invoice for that service period.

(5) If the 867_03 is cancelled after the TDSP has sent the 810_02 transaction, the TDSP will cancel the 810_02 transaction. If the 810_02 transaction error is not related to consumption, the TDSP may cancel the 810_02 transaction and not the 867_03 transaction.

24.3 Monthly Remittance

Transmission and/or Distribution Service Providers (TDSPs) and Competitive Retailers (CR) shall use the following transactions to remit monthly payments.

24.3.1 Competitive Retailer to Transmission and/or Distribution Service Provider Monthly Remittance Advice

(1) This transaction set, from the CR to the TDSP, is used by the CR to notify the TDSP of payment details related to a specific invoice. A CR must pass an 820_02, CR Remittance Advice, for every invoice (original, cancel, replacement) received, validated, and accepted by the CR even when a cancel and restatement of usage subsequently cancels the original invoice.

(2) Each Market Participant is responsible for ensuring that the data provided in the 820_02 transaction is presented in a format that is consistent with market specifications prescribed in the Texas Standard Electronic Transaction (TX SET) Implementation Guide posted on the ERCOT website.

24.3.1.1 Remittance Advice Total Matches Payment Total

The remittance advice must match the total payment. The CR must ensure that the remittance advice and the payment instructions have the same (matching) trace/reference numbers. A one-to-one correlation must be maintained between payments and remittance advices. It is acceptable for one payment and one remittance advice to include many invoices. It is not acceptable for several payments to reference one remittance advice. Every payment trace/reference number sent via the bank must match a remittance advice trace/reference number sent to the TDSP. The trace/reference number must be unique for each associated payment and remittance advice.

24.3.1.2 Negative Remittance Advice

A negative remittance advice is not allowed in the Texas retail market. If the adjustments are larger than the payments (creating a negative remittance advice), payments must be held until the CR can submit a net positive remittance advice as a credit against the overpayment. It is not necessary for a CR to hold an adjustment amount until the CR has accumulated sufficient invoices to result in a complete offset of the overpayment. Instead the CR may use the adjustment amount by taking a partial credit on another Invoice. If the CR has determined that the negative remittance cannot be offset within a reasonable amount of time, the CR will contact the TDSP to resolve the situation.

24.3.1.3 Acceptable Payment Methods

Acceptable payment methods are CCD+, CTX and Fed wire.

24.3.1.4 Warehousing an 820 Remittance Advice

When the payment instruction and the remittance advice are generated separately, the TDSP will warehouse the 820_02, CR Remittance Advice, until the payment instructions received by the CR's bank cause the money to be deposited in the TDSP's account. The payment instruction and remittance shall be transmitted within five Business Days of each other. The remittance advice and payment instruction dollar amount must balance to the corresponding transaction. Payment will be considered received on the date company's bank receives the electronic funds transfer or wire transfer and the appropriate remittance advice is received by the company in accordance with the requirements specified by Applicable Legal Authorities (ALA).

24.4 Municipally Owned Utility/Electric Cooperative Transmission and/or Distribution Service Provider to Competitive Retailer Monthly Remittance Advice

(1) This transaction set, from a Municipally Owned Utility's (MOU) Transmission and/or Distribution Service Provider (TDSP) or an Electric Cooperative's (EC) TDSP (MOU/EC TDSP) to the Competitive Retailer (CR) is used by the MOU/EC TDSP to notify the CR of payment details related to a specific Invoice. A MOU/EC TDSP must pass an 820_03, MOU/EC Remittance Advice, for every CR account number even when a cancel and restatement of usage subsequently cancels the original invoice.

(2) Each Market Participant is responsible for ensuring that the data provided in the 820_03 transaction is presented in a format that is consistent with the market specifications in the Texas Standard Electronic Transaction (TX SET) Implementation Guide.

24.4.1 Timing 820 Remittance to CR

When the payment is received from the retail Customer on behalf of the CR, MOU/EC TDSP shall send the payment instructions within five Retail Business Days of the due date of the retail Customer's bill, or if the Customer has paid after the due date, five Business Days after the MOU/EC TDSP has received payment. Payment instruction shall cause the money to be deposited in the CR's account. There should not be more than five Business Days difference in the receipt of the payment instruction and the remittance advice.

24.4.2 Remittance Advice Total Matches Payment Total

The remittance advice must match the total payment. The MOU/EC TDSP must ensure that the remittance advice and the payment instructions have the same (matching) trace/reference numbers. A one-to-one correlation must be maintained between payments and remittance advice. It is acceptable for one payment and one remittance advice to include many invoices. It is not acceptable for several payments to reference one remittance advice. Every payment trace/reference number sent via the bank must match a remittance advice trace/reference number sent to the CR. The trace/reference number must be unique for each associated payment and remittance advice.

24.4.3 Negative Remittance Advice

A negative remittance advice is not allowed in the Texas market. If the adjustments are larger than the payments (creating a negative remittance advice), payment must be held until the MOU/EC TDSP can submit a net positive remittance advice as a credit against the overpayment. It is not necessary for a MOU/EC TDSP to hold an adjustment amount until the MOU/EC TDSP has accumulated sufficient Invoices to result in a complete offset of the overpayment. Instead the MOU/EC TDSP may use the adjustment amount by taking a partial credit on another Invoice. If the MOU/EC TDSP has determined that the negative remittance cannot be offset within a reasonable amount of time, the MOU/EC TDSP will contact the CR to resolve the situation.

24.4.4 Acceptable Payment Methods

Acceptable payment instruction methods are CCD+, CTX, check, and Fed wire.

24.4.5 Warehousing an 820 Remittance Advice

When the payment instruction and the remittance advice are generated separately, the CR may warehouse the 820_03, MOU/EC Remittance Advice, until the payment instructions received by the MOU/EC TDSP's bank cause the money to be deposited in the CR's account.

24.5 Maintain Customer Information Request

This transaction set, from a Competitive Retailer (CR) to a Transmission and/or Distribution Service Provider (TDSP), is used for CRs who have chosen Options 2 and 3 concerning service orders and/or outages. A CR choosing Option 2 or 3 shall be required to provide the TDSP with the information necessary to verify CR's retail Customer's identity (name, address, and home or contact telephone number) for a particular point of delivery served by the CR and to continually provide the TDSP updates of such information.

24.5.1 Timing of 814_PC Maintain Customer Information Request from Competitive Retailer

This transaction shall be transmitted from the CR of Record to the TDSP in one Retail Business Day only after the CR has received an 867_04, Initial Meter Read, from the TDSP for that specific move in Customer. Also, the CR shall not transmit this transaction and/or provide any updates to the TDSP after receiving a final reading via an 867_03, Monthly or Final Usage, for that specific move-out Customer. The TDSP shall provide the 814_PD, Maintain Customer Information Response, in one Retail Business Day acknowledging receipt of the 814_PC, Maintain Customer Information Request, which would indicate that the TDSP accepts or rejects the transaction.

24.6 MOU/EC TDSP to CR Maintain Customer Information Request

This transaction set, from a Municipally Owned Utility (MOU)/Electric Cooperative (EC) Transmission and/or Distribution Service Provider (TDSP) to the Competitive Retailer (CR), is used by the MOU/EC TDSP to provide the CR with Customer information (name, address, membership id, and home or contact telephone number) for a particular point of delivery served by both the MOU/EC TDSP and CR and to continually provide the CR updates of such information. MOU/EC TDSPs in a MOU/EC service territory are more likely to have current Customer information due to the fact that they maintain contact with the Customer and perform billing functions.

24.6.1 Timing of 814_PC Maintain Customer Information Request from Municipally Owned Utility/Electric Cooperative Transmission and/or Distribution Service Provider

This transaction shall be transmitted from the MOU/EC TDSP to the CR in one Retail Business Day upon an update in Customer information. The CR shall provide the 814_PD, Maintain Customer Information Response, in one Retail Business Day acknowledging receipt of the 814_PC, Maintain Customer Information Request, which would indicate that the CR accepts or rejects the transaction.

ERCOT Nodal Protocols

Section 25: Market Suspension and Restart

November 15, 2022

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25 MARKET SUSPENSION AND RESTART

25.1 Introduction

(1) A Market Suspension triggering event may result in the suspension and restart of market activity, including but not limited to:

(a) Day-Ahead Market (DAM) activities;

(b) Real-Time Market (RTM) activities;

(c) Congestion Revenue Right (CRR) Auctions;

(d) Market credit activities;

(e) Retail market activities;

(f) Network Operations Model updates;

(g) Market reporting activities; and

(h) Other impacted ERCOT operations and activities.

(2) A Market Suspension will be declared by ERCOT at its sole discretion and communicated to Market Participants in as timely a manner as feasible, given the constraints of the triggering event.

25.2 Market Suspension Principles

(1) The specific activities that will take place during a Market Suspension will depend on the nature of the triggering event, the extent to which market-supporting systems and processes have been curtailed, and other specific circumstances. However, in acting to restore markets, ERCOT shall act in accordance with the following principles:

(a) ERCOT shall use its crisis communication procedures to foster orderly and timely communication of information with the Public Utility Commission of Texas (PUCT), other Governmental Authorities, Market Participants and stakeholders, the media, and the general public.

(b) During Market Suspension, ERCOT shall act in accordance with the State of Texas Emergency Management Plan (Annex L).

(c) Restart of the Real-Time Market (RTM) will be prioritized before other markets and activities.

(d) Congestion Revenue Right (CRR) Auctions and related functions will start only after the RTM and Day-Ahead Market (DAM) are restored. CRR Auctions will be rescheduled on a best efforts basis. CRR Auctions may be cancelled.

(e) In the event of market outage where there are DAM awards with no corresponding Security-Constrained Economic Dispatch (SCED) execution, or CRRs with no corresponding DAM execution, these results will be invalidated for the hours corresponding to the Market Suspension.

(f) Certain transactions, such as trades, DAM bids and offers, and CRR bids and offers, may be restricted until such time as supporting systems are deemed stable.

(g) Limited Settlement functionality is expected while restoring ERCOT markets. To the extent data are available, reconciliation Settlements may be produced after ERCOT market operations are fully restored.

(h) Payments to Qualified Scheduling Entities (QSEs) representing Resources shall be made in as timely a manner as possible to support recovery of market functionality.

(i) As necessary, QSEs representing Resources that support restoration of the ERCOT Transmission Grid shall be made whole to their costs as described in Section 25.5.2, Market Suspension Make-Whole Payment.

(j) Startup Costs and operating costs incurred during a Market Suspension shall be uplifted on a Load Ratio Share (LRS) basis after Market Restart. If necessary to avoid financial disruption to Market Participants, uplift charges may be assessed on an installment basis.

(k) If additional liquidity is required during a Market Suspension, ERCOT may utilize available funds such as undistributed CRR Auction Revenues before seeking emergency funding to pay QSEs representing Resources.

(l) Credit and collateral requirements will be reviewed by ERCOT staff as appropriate to facilitate Market Restart. This could include relaxation of credit requirements and release of cash or other collateral to provide short-term Market Participant liquidity.

(m) Potential Mass Transitions arising in consequence of the event shall be suspended.

(n) Retail operations will follow the processes outlined in Retail Market Guide Section 7.10, Extended Unplanned Outage, and related supporting documentation.

(o) ERCOT will call a special ERCOT Board meeting prior to effectuating Market Restart for the DAM and RTM.

25.3 Market Restart Processes

(1) Specific Market Restart processes may be modified depending on the nature of the triggering event.

(2) Market Restart processes work in conjunction with, but will not supersede, other ERCOT emergency processes and procedures such as Black Start procedures.

(3) Following a declaration by ERCOT of a Market Suspension, in effectuating Market Restart for the Real-Time Market (RTM), ERCOT:

(a) Shall determine the interval to resume Security-Constrained Economic Dispatch (SCED) execution based on availability and functioning of:

(i) The Energy Management System (EMS);

(ii) The Market Management System (MMS);

(iii) The ERCOT System operating as a single Island as described in the Nodal Operating Guides; and

(iv) Electronic communications between ERCOT and Market Participants.

(b) Shall suspend all RTM Settlements and shall settle pursuant to Section 25.5, Market Suspension and Market Restart Settlement;

(c) Shall suspend Day-Ahead Market (DAM) Settlements for any Operating Days for which ERCOT declares the RTM was suspended;

(d) May assign Ancillary Services once the ERCOT System is operating as a single Island as described in the Nodal Operating Guides, and ERCOT is ready to control the system using Load Frequency Control (LFC); and

(e) Shall not restart the RTM until ERCOT has satisfied paragraph (6) below.

(4) When there are no posted DAM results for the Operating Day, and operational conditions allow, ERCOT shall assign Ancillary Services to Qualified Scheduling Entities (QSEs) based on the amount of capacity that their Resources have or can bring On-Line.

[NPRR1013: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) When there are no posted DAM results for the Operating Day, and operational conditions allow, ERCOT shall assign Ancillary Services to Qualified Scheduling Entities (QSEs) based on the amount of capacity that their Resources have or can bring On-Line. This process will remain in place until the RTM is able to award Ancillary Services to Resources.

(5) Following a declaration by ERCOT of a Market Suspension, in effectuating a Market Restart for the DAM, ERCOT shall restart the DAM when the below conditions are satisfied:

(a) The RTM has restarted pursuant to paragraph (3) above;

(b) ERCOT is reasonably able to model the expected state of the ERCOT Transmission Grid for the next day;

(c) ERCOT is able to receive market submissions to successfully run the DAM; and

(d) ERCOT has satisfied paragraph (6) below.

(6) ERCOT shall not restart the RTM or DAM until:

(a) The ERCOT Board has approved the restart and ERCOT has issued a Market Notice stating that the ERCOT Board has approved the restart; or

(b) If, after taking into consideration the possibility of conducting an urgent meeting and holding such meeting by teleconference as set forth in paragraphs (b) and (c) of Section 4.6, Meetings, of the ERCOT Bylaws, it is not reasonably practicable to obtain ERCOT Board approval prior to the restart, the ERCOT CEO, or if designated by the ERCOT CEO, the ERCOT General Counsel, have approved the restart.

(i) The ERCOT CEO or ERCOT General Counsel shall not approve a restart of the RTM or DAM pursuant to this paragraph (b) unless the ERCOT CEO or ERCOT General Counsel has consulted with each Market Segment Director or Segment Alternate to the extent a Market Segment Director is unavailable (as such terms are defined in the ERCOT Bylaws) and a majority of the Market Segment Directors and Segment Alternates consulted agree in writing to restart the RTM or DAM as proposed by ERCOT.

(ii) Prior to restarting the RTM or DAM pursuant to this paragraph (b), ERCOT shall issue a Market Notice stating that it was not reasonably practicable to obtain ERCOT Board approval prior to the restart, however, the majority of the Market Segment Directors and Segment Alternates have agreed in writing to restart the RTM or DAM.

(7) During the Market Restart process, credit constraints may be relaxed as applicable as detailed in Section 25.4, Market Suspension Credit Processes.

25.4 Market Suspension Credit Processes

25.4.1 Market Suspension Credit Assumptions

(1) During a Market Suspension, the estimation of market credit is contingent upon the following conditions:

  (a) ERCOT systems critical to credit processes have been restored, with the understanding that some data normally used in credit calculations might not be available;

  (b) Adequate means of communication with Counter-Parties are available; and

  (c) Systems are available for transfer of funds to and from Market Participants.

25.4.2 Determination of Counter-Party Available Credit Limits

(1) During a Market Suspension, a Counter-Party's Available Credit Limit for the CRR Auction (ACLC) and Available Credit Limit for the DAM (ACLD) will be determined pursuant to Section 16.11.4.6, Determination of Counter-Party Available Credit Limits.

(2) During a Market Suspension, ERCOT may, at its sole discretion, set an Unsecured Credit Limit for Counter-Parties not otherwise eligible per the ERCOT Creditworthiness Standards and/or increase Unsecured Credit Limits for Counter-Parties currently eligible for Unsecured Credit.

[NPRR1112: Delete paragraph (2) above upon system implementation and October 1, 2023, and renumber accordingly.]

(3) In accordance with Section 25.4.3, Collateral Management, ERCOT may, at its sole discretion, waive, in part or in full, the requirements in paragraph (2) of Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness Credit Exposure by ERCOT, for Counter-Parties to maintain designated amounts of Secured and/or Remainder Collateral.

(4) The exercise of any measures described in paragraphs (2) and (3) above shall be reflected in the estimated ACLC and/or ACLD values provided to Counter-Parties pursuant to Section 16.11.4.6.

[NPRR1112: Replace paragraph (4) above with the following upon system implementation and October 1, 2023:]

(4) The exercise of any measures described in paragraph (2) above shall be reflected in the estimated ACLC and/or ACLD values provided to Counter-Parties pursuant to Section 16.11.4.6.

25.4.3 Collateral Management

(1) During a Market Suspension, and for no more than two Bank Business Days following restart of the Day-Ahead Market (DAM), ERCOT may, at its sole discretion, forego the requirement in paragraph (3) of Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness Credit Exposure by ERCOT, to provide prompt notice to Counter-Parties of the need to increase Financial Security.

(2) During a Market Suspension, and for no more than two Bank Business Days following restart of the DAM, ERCOT may, at its sole discretion, extend the timelines in paragraph (6) of Section 16.11.5 to allow Counter-Parties to make arrangements to provide collateral, without unmet requests for collateral being designated as Late Payments.

25.5 Market Suspension and Market Restart Settlement

25.5.1 Settlement Activity for a Market Suspension

(1) Settlement for the Operating Days for which the Real-Time Market (RTM) has been suspended shall be limited to the following payments and charges:

(a) Market Suspension Make-Whole Payment;

(b) Market Suspension Direct Current Tie (DC Tie) Import Payment;

(c) Market Suspension Block Load Transfer Payment;

(d) Reliability Must-Run (RMR) Standby Payment;

(e) RMR Payment for Energy;

(f) Black Start Hourly Standby Fee Payment;

(g) Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(h) Market Suspension Charge Allocation; and

(i) ERCOT System Administration Fee.

(2) During a Market Suspension:

(a) To the extent feasible, ERCOT shall calculate and pay the Real-Time Market Suspension Make-Whole Payment to each eligible Qualified Scheduling Entity (QSE).

(b) ERCOT shall wire the funds to the QSE's banking institution as soon as practicable, subject to the availability of funds and the availability of systems for transfer of funds.

(c) At its sole discretion, ERCOT may suspend calculating monthly verifiable cost updates.

(d) ERCOT shall not assess:

(i) Market Suspension Charge Allocation as defined in Section 25.5.5, Market Suspension Charge Allocation;

(ii) Market Suspension DC Tie Import Payment as defined in Section 25.5.3, Market Suspension DC Tie Import Payment;

(iii) Market Suspension Block Load Transfer Payment as defined in Section 25.5.4, Market Suspension Block Load Transfer Payment;

(iv) RMR Standby Payment;

(v) RMR Payment for Energy;

(vi) Black Start Hourly Standby Fee Payment; and

(vii) ERCOT System Administration Fee.

(3) ERCOT may, at its sole discretion, settle the Operating Days that occur during a Market Suspension without use of RTM Settlement Statements, Settlement Invoices, and associated provisions, as described in Section 9, Settlement and Billing.

(4) ERCOT shall maintain available supporting billing determinant Settlement data for Market Suspension Operating Day Settlement and shall provide this information to each QSE as soon as practicable.

(5) ERCOT shall cease to utilize the provisions for Market Suspension Settlement beginning with the first complete Operating Day for which ERCOT issues Dispatch Instructions to QSEs in accordance with Section 25.3, Market Restart Processes.

(6) After Market Restart ERCOT shall:

(a) Reconcile payments to QSEs with Generation Resources pursuant to Section 25.5.2, Market Suspension Make-Whole Payment, using the best available generation data;

(b) Calculate Market Suspension DC Tie Import Payments as defined in Section 25.5.3;

(c) Calculate Market Suspension Block Load Transfer Payments as defined in Section 25.5.4;

(d) Calculate Market Suspension RMR Standby Payments in accordance with Section 6.6.6.1, RMR Standby Payment;

(e) Calculate Market Suspension RMR Payment for Energy in accordance with Section 6.6.6.2, RMR Payment for Energy;

(f) Calculate Market Suspension Black Start Service in accordance with Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(g) Allocate costs in accordance with Section 25.5.5; and

(h) Assess the ERCOT System Administration Fee for the time period of the Market Suspension in accordance with Section 9.16.1, ERCOT System Administration Fee, using the best available Load data.

(7) ERCOT shall provide Notice no less than two Business Days prior to issuing any reconciliation Settlement for the impacted period.

(8) ERCOT shall resume other Settlement activities that were suspended as a result of, or in relation to, the Market Suspension as soon as practicable following the Market Restart, including, but not limited to, pending Congestion Revenue Right (CRR), Day-Ahead Market (DAM) and RTM Settlement for Operating Days prior to the Market Suspension.

25.5.2 Market Suspension Make-Whole Payment

(1) To compensate QSEs representing Generation Resources for providing energy during a Market Suspension, ERCOT shall calculate a Market Suspension Make-Whole Payment for the Operating Day as follows:

[NPRR1029: Replace paragraph (1) above with the following upon system implementation:]

(1) To compensate QSEs representing Generation Resources or Energy Storage Resources (ESRs) for providing energy during a Market Suspension, ERCOT shall calculate a Market Suspension Make-Whole Payment for the Operating Day as follows:

$$\text{MSMWAMT}_{q,\,r,\,d} = (-1) * (\text{MSSUC}_{q,\,r,\,d} + \text{MSOC}_{q,\,r,\,d} + \text{MSSUCADJ}_{q,\,r,\,d} + \text{MSOCADJ}_{q,\,r,\,d})$$

Where,

The startup cost (MSSUC) is calculated as follows:

For Black Start Resources:

$$\text{MSSUC}_{q,\,r,\,d} = \$0.00$$

For Combined Cycle Trains:

$$\text{MSSUC}_{q,\,r,\,d} = \sum_{s} \text{MSSUPR}_{q,\,r,\,\text{s}} + \sum_{t} (\text{MAX}\ (0,\ \text{MSSUPR}_{\text{afterCCGR}} - \text{MSSUPR}_{\text{beforeCCGR}}))$$

For all other Resources:

$$\text{MSSUC}_{q,\,r,\,d} = \sum_{s} \text{MSSUPR}_{q,\,r,\,s}$$

The startup price (MSSUPR) and operating cost (MSOC) are calculated as follows:

If ERCOT has approved verifiable costs for the Generation Resource:

For Firm Fuel Supply Resources (FFSRs) starting with a reserved fuel

$$\text{MSSUPR}_{q,\,r,\,s} = \text{RVOMS}_{q,\,r,\,s}$$

$$\text{MSOC}_{q,\,r,\,d} = \sum_{i} (\text{ROM}_{q,\,r}) * \text{MSGEN}_{q,\,r,\,i}$$

Otherwise,

$$\text{MSSUPR}_{q,\,r,\,s} = \text{RABCFCRS}_{q,\,r,\,s} * (\text{MSAVGFP} + \text{FA}_{q,\,r}) + \text{RVOMS}_{q,\,r,\,s}$$

$$\text{MSOC}_{q,\,r,\,d} = \sum_{i} (\text{AHR}_{q,\,r,\,i} * (\text{MSAVGFP} + \text{FA}_{q,\,r}) + \text{ROM}_{q,\,r}) * \text{MSGEN}_{q,\,r,\,i}$$

If ERCOT has not approved verifiable costs for the Generation Resource:

For FFSRs starting with a reserved fuel

$$\text{MSSUPR}_{q,\,r,\,s} = \text{RCGSC}$$

$$\text{MSOC}_{q,\,r,\,d} = \sum_{i} (\text{STOM}_{rc}) * \text{MSGEN}_{q,\,r,\,i}$$

Otherwise,

$$\text{MSSUPR}_{q,\,r,\,s} = \text{RCGSC}$$

$$\text{MSOC}_{q,\,r,\,d} = \sum_{i} (\text{PAHR}_{r,\,i} * (\text{MSAVGFP} + \text{PFA}_{rc}) + \text{STOM}_{rc}) * \text{MSGEN}_{q,\,r,\,i}$$

Where,

MSAVGFP = MSAVGFIP for Generation Resources that indicate in the Resource Registration process or the verifiable cost process to start on natural gas

[NPRR1029: Replace the formula for "MSAVGP" above with the following upon system implementation:]

MSAVGFP = MSAVGFIP for Generation Resources that indicate in the Resource Registration process or the verifiable cost process to start on natural gas. For ESRs, the MSAVGFIP shall be set to zero.

Or,

MSAVGFP = MSAVGFOP for Generation Resources that indicate in the Resource Registration process or through the verifiable cost process to start on fuel oil

The above variables are defined as follows:

Variable	**Unit**	**Definition**
MSMWAMT $_{q, r, d}$	$	*Market Suspension Make-Whole Payment* – The Market Suspension Make-Whole Payment to the QSE *q,* for Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MSSUCADJ $_{q, r, d}$	$	*Market Suspension Startup Costs Adjustment* – Adjustment to the Market Suspension Make-Whole Payment to pay or charge the QSE *q* for actual costs related to starting up Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MSOCADJ $_{q, r, d}$	$	*Market Suspension Operating Costs Adjustment* – Adjustment to the Market Suspension Make-Whole Payment to pay or charge the QSE *q* for actual costs for operating Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MSSUC $_{q, r, d}$	$	*Market Suspension Startup Cost* – The Startup Costs for Resource *r* represented by QSE *q* during restart hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MSSUPR $_{q, r, s}$	$	*Market Suspension Startup Price per Start* – The Market Suspension Settlement price for Resource *r* represented by QSE *q* for the start *s*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RABCFCRS $_{q, r, s}$	MMBtu / start	*Raw Actual Breaker Close Fuel Consumption Rate per Start* – The raw actual verifiable fuel consumption rate, from first fire to breaker close, for the Resource *r* represented by QSE *q*, per start *s,* for the warmth state, as submitted through the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MSOC $_{q, r, d}$	$	*Market Suspension Operating Cost* – The Market Suspension operating cost for Resource *r* represented by QSE *q* for operations after breaker close for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RVOMS $_{q, r, s}$	$/start	*Raw Verifiable Operations and Maintenance Cost per Start* – The raw verifiable Operations and Maintenance (O&M) cost for the Resource *r* represented by QSE *q*, per start *s,* for the warmth state, as submitted through the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	**Unit**	**Definition**
$\text{ROM}_{q, r}$	$/MWh	*Raw Verifiable Operations and Maintenance Cost Above LSL* – The raw verifiable O&M cost for the Resource *r* represented by QSE *q* for operations above Low Sustained Limit (LSL). Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
STOM_{rc}	$/MWh	*Standard Operations and Maintenance Cost* – The standard O&M cost for the Resource category *rc* for operations above LSL, shall be set to the minimum energy variable O&M costs, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs. ***[NPRR1029: Replace the definition above with the following upon system implementation:]*** *Standard Operations and Maintenance Cost* – The standard O&M cost for the Resource category *rc* for operations above LSL, shall be set to the minimum energy variable O&M costs, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs. For an ESR, STOM shall be set at $0.3/MWh and for a DC-Coupled Resource, the value shall be set at $4.40/MWh.
MSAVGFP	$/MMBtu	*Market Suspension Average Fuel Price* – The Market Suspension average fuel price calculated based on MSAVGFIP or MSAVGFOP.
MSAVGFIP	$/MMBtu	*Market Suspension Average Fuel Index Price* – The Market Suspension average Fuel Index Price (FIP) calculated as the average price of FIP for the 15 days prior to the Market Suspension event, calculated on a daily rolling basis for Operating Days the index price is available to ERCOT.
MSAVGFOP	$/MMBtu	*Market Suspension Average Fuel Oil Price* – The Market Suspension average Fuel Oil Price (FOP) calculated as the average price of FOP for the 15 days prior to the Market Suspension event, calculated on a daily rolling basis for Operating Days the index price is available to ERCOT.
RCGSC	$/start	*Resource Category Generic Startup Cost* – The Resource Category Generic Startup Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$\text{FA}_{q, r}$	$/MMBtu	*Verifiable Average Fuel Adder* – The verifiable average fuel price adder for the Resource *r* represented by QSE *q*. The fuel adder shall be set to the actual approved verifiable fuel adder or the standard value defined in the Verifiable Cost Manual. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
PFA_{rc}	$/MMBtu	*Proxy Fuel Adder* – The proxy fuel price adder for the Resource category *rc*. For all thermal Generation Resources, the fuel adder shall be set to $0.50/MMBtu; otherwise, the fuel adder shall be set to $0.00/MMBtu.
$\text{AHR}_{q, r, i}$	MMBtu / MWh	*Average Heat Rate per Resource* – The verifiable average heat rate for the Resource *r* represented by QSE *q*, for operating levels between LSL and High Sustained Limit (HSL), for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	Unit	Definition
PAHR $_{r,\,i}$	MMBtu / MWh	*Proxy Average Heat Rate* – The proxy average heat rate for the Resource *r* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MSGEN $_{q,\,r,\,i}$	MWh	*Market Suspension Generation per Resource* – The generation for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval *i*.
q	None	A QSE.
r	None	A Generation Resource. ***[NPRR1029: Replace the definition above with the following upon system implementation:]*** A Generation Resource or ESR.
d	None	An Operating Day during a Market Suspension event.
i	None	A 15-minute Settlement Interval within the hour of an Operating Day of a Market Suspension event.
s	None	A Generation Resource start during an Operating Day of a Market Suspension event.
t	None	A transition that is eligible to have its costs included in the Market Suspension Startup Cost.
rc	None	A Resource category.
afterCCGR	None	The Combined Cycle Generation Resource to which a Combined Cycle Train transitions.
beforeCCGR	None	The Combined Cycle Generation Resource from which a Combined Cycle Train transitions.

(2) The total compensation to each QSE for the Market Suspension Make-Whole Payment for an Operating Day is calculated as follows:

$$\textbf{MSMWAMTQSETOT}_{\boldsymbol{q,\,d}} = \sum_{r} \textbf{MSMWAMT}_{\boldsymbol{q,\,r,\,d}}$$

And,

$$\text{MSMWAMTTOT}_{d} = \sum_{q} \text{MSMWAMTQSETOT}_{q,\,d}$$

The above variables are defined as follows:

Variable	Unit	Definition
MSMWAMTQSETOT $_{q,\,d}$	$	*Market Suspension Make-Whole Payment per QSE* – The total payment to QSE *q* for Market Suspension Make-Whole Payment for the Operating Day *d*.
MSMWAMTTOT $_{d}$	$	*Market Suspension Make-Whole Payment Total* – The total payment to all QSEs for Market Suspension Make-Whole Payment for the Operating Day.

Variable	**Unit**	**Definition**
MSMWAMT $_{q, r, d}$	$	*Market Suspension Make-Whole Payment* – The Market Suspension Make-Whole Payment to the QSE *q,* for Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A Generation Resource. ***[NPRR1029: Replace the definition above with the following upon system implementation:]*** A Generation Resource or ESR.
d	none	An Operating Day during a Market Suspension event.

(3) During a Market Suspension, ERCOT may cease making payments in accordance with this Section in the event that funds are not available to make such payments.

25.5.3 Market Suspension DC Tie Import Payment

(1) To compensate each QSE for energy imported into the ERCOT System through each DC Tie during a Market Suspension, the payment for an Operating Day is calculated as follows:

$$\text{MSEDCIMPAMT}_{q,\,p,\,d} = (-1) * \sum_{i} (\text{MSVEEPDCTP}_{q,\,p,\,i} * \text{MSCAEDCT} * \text{MSEDCIMP}_{q,\,p,\,i} * ¼)$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
MSEDCIMPAMT $_{q, p, d}$	$	*Market Suspension Emergency DC Import Amount per QSE per Settlement Point* – The payment to QSE *q* for emergency energy imported through DC Tie *p*, during a Market Suspension*,* for the Operating Day *d*.
MSEDCIMP $_{q, p, i}$	MW	*Market Suspension Emergency DC Import per QSE per Settlement Point* – The aggregated DC Tie Schedule for emergency energy imported by QSE *q* into the ERCOT System during a Market Suspension condition through DC Tie *p*, for the 15-minute Settlement Interval *i*.
MSVEEPDCTP $_{q, p, i}$	$/MWh	*Market Suspension Verified Emergency Energy Price at DC Tie Point* – The ERCOT verified cost for the energy imported by QSE *q* into the ERCOT System during a Market Suspension through a DC Tie *p* as instructed by a Dispatch Instruction, for the 15-minute Settlement Interval *i*.
MSCAEDCT	none	*Market Suspension Cost Adder for Emergency DC Tie Import* – A multiplier of 1.10.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

i	none	A 15-minute Settlement Interval within the hour of an Operating Day of a Market Suspension event.
d	none	An Operating Day during a Market Suspension event.

(2) The total payment to each QSE for all energy imported into the ERCOT System during a Market Suspension through DC Ties for the Operating Day is calculated as follows:

$$\text{MSEDCIMPAMTQSETOT}_{q,\,d} = \sum_{p} \text{MSEDCIMPAMT}_{q,\,p,\,d}$$

And,

$$\text{MSEDCIMPAMTTOT}_{d} = \sum_{q} \text{MSEDCIMPAMTQSETOT}_{q,\,d}$$

The above variables are defined as follows:

Variable	Unit	Definition
MSEDCIMPAMTQSETOT $_{q,\,d}$	$	*Market Suspension Emergency DC Import Amount Total per QSE* – The total of the payments to QSE *q* for DC Tie import emergency energy imported into the ERCOT System during a Market Suspension condition through DC Ties, for the Operating Day *d*.
MSEDCIMPAMT $_{q,\,p,\,d}$	$	*Market Suspension Emergency DC Import Amount per QSE per Settlement Point* – The payment to QSE *q* for emergency energy imported through DC Tie *p,* for the Operating Day *d*.
MSEDCIMPAMTTOT $_{d}$	$	*Market Suspension Emergency DC Import Amount Total* – The total Market Suspension Emergency DC Import Amount charges for all QSEs.
q	none	A QSE.
p	none	A DC Tie Settlement Point.
d	none	An Operating Day during a Market Suspension event.

25.5.4 Market Suspension Block Load Transfer Payment

(1) The total payment to each QSE for the energy delivered to an ERCOT Load through a Block Load Transfer (BLT) Point that is moved in response to an ERCOT Verbal Dispatch Instruction (VDI) for an Operating Day during a Market Suspension is calculated as follows:

$$\text{MSBLTRAMT}_{q,\,bltp,\,p,\,d} = (-1) * \sum_{i} (\text{MSVEEPBLTP}_{q,\,bltp,\,i} * \text{MSCABLT} * \text{BLTR}_{q,\,p,\,bltp,\,i})$$

The above variables are defined as follows:

Variable	Unit	Definition
MSBLTRAMT $_{q,\,bltp,\,p,\,d}$	$	*Market Suspension Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point* – The payment to QSE *q* for the BLT Resource

		that delivers energy to Load Zone *p* through BLT Point *bltp* during a Market Suspension, for the Operating Day *d*.
$\text{MSVEEPBLTP}_{q,\ bltp,\ i}$	\$/MWh	*Market Suspension Verified Emergency Energy Price at BLT Point* – The ERCOT verified cost for the energy delivered to an ERCOT Load through BLT Point *bltp*, represented by QSE *q* during a Market Suspension event in ERCOT as determined by an ERCOT VDI, for the 15-minute Settlement Interval *i*.
MSCABLT	none	*Market Suspension Cost Adder for Block Load Transfer* – A multiplier of 1.10.
$\text{BLTR}_{q,\ p,\ bltp,\ i}$	MWh	*Block Load Transfer Resource per QSE per Settlement Point per BLT Point* – The energy delivered to an ERCOT Load in Load Zone *p* through BLT Point *bltp* represented by QSE *q*, during a Market Suspension event, for the 15-minute Settlement Interval *i*.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.
i	none	A 15-minute Settlement Interval within the hour of an Operating Day of a Market Suspension event.
d	none	An Operating Day during a Market Suspension event.

(2) The total payment to each QSE for all energy delivered to ERCOT Loads through BLT Points during a Market Suspension event for the Operating Day is calculated as follows:

$$\text{MSBLTRAMTQSETOT}_{q,\ d} = \sum_{p} \sum_{bltp} \text{MSBLTRAMT}_{q,\ bltp,\ p,\ d}$$

And,

$$\text{MSBLTRAMTTOT}_{d} = \sum_{q} \text{MSBLTRAMTQSETOT}_{q,\ d}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{MSBLTRAMTQSETOT}_{q,\ d}$	\$	*Market Suspension Block Load Transfer Amount Total per QSE* – The total payment to QSE *q* for energy delivered into the ERCOT System through BLT Points during a Market Suspension for the Operating Day *d*.
$\text{MSBLTRAMT}_{q,\ bltp,\ p}$	\$	*Market Suspension Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point* – The payment to QSE *q* for the BLT Resource that delivers energy to Load Zone *p* through BLT Point *bltp* during a Market Suspension for the Operating Day *d*.
MSBLTRAMTTOT_{d}	\$	*Market Suspension Block Load Transfer Amount Total* – The total Market Suspension Block Load Transfer Amount for all QSEs for the Operating Day *d*.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.
d	none	An Operating Day during a Market Suspension event.

25.5.5 Market Suspension Charge Allocation

(1) After resumption of the RTM, and in accordance with Section 25.5.1, Settlement Activity for a Market Suspension, ERCOT shall allocate the cost on a Load Ratio Share (LRS) basis for the cost to:

(a) Reimburse QSEs representing Resources for Market Suspension Make-Whole Payments in accordance with Section 25.5.2, Market Suspension Make-Whole Payment;

(b) Reimburse QSEs for Market Suspension DC Tie Import Payments in accordance with Section 25.5.3, Market Suspension DC Tie Import Payment;

(c) Reimburse QSEs for Market Suspension Block Load Transfer Payments in accordance with Section 25.5.4, Market Suspension Block Load Transfer Payment;

(d) Reimburse QSEs for Market Suspension RMR Standby Payments in accordance with Section 6.6.6.1, RMR Standby Payment;

(e) Reimburse QSEs for Market Suspension RMR Payment for Energy in accordance with Section 6.6.6.2, RMR Payment for Energy;

(f) Reimburse QSEs for Market Suspension Firm Fuel Supply Service Standby Payment and Fuel Replacement Cost Recovery Payment in accordance with Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(g) Reimburse QSEs for Market Suspension Black Start Service in accordance with Section 6.6.8.1, Black Start Hourly Standby Fee Payment; and

[NPRR1029: Insert paragraph (h) below upon system implementation and renumber accordingly:]

(h) Reimburse QSEs representing ESRs for approved charging costs incurred prior to the Market Suspension; and

(h) Pay any other unfunded non-recurring costs incurred in restarting ERCOT markets.

(2) ERCOT shall charge for the costs described above through the Market Suspension Charge Allocation.

(a) These charges shall be initially allocated on an LRS basis for the most recent 30 days prior to the Market Suspension event for which Initial Settlement has been completed. For purposes of this charge, a QSE's basis shall be the QSE's total Real-Time Adjusted Metered Load (AML) for the 30 days prior to the Market

Suspension divided by the total ERCOT Real-Time AML for the same period. The initial Market Suspension Charge to each QSE for a given Operating Day is calculated as follows:

$$\text{LARTMSAMT}_{q} = (-1) * (\text{MSMWAMTTOT}_{d} + \text{MSEDCIMPAMTTOT}_{d} + \text{MSBLTRAMTTOT}_{d} + \sum_{h} \text{RMRSBAMTTOT} + \sum_{h} \text{RMREAMTTOT} + \sum_{h} \text{BSSAMTTOT}) * \text{RTMSLRS}_{q}$$

Where:

$$\text{RTMSLRS}_{q} = \text{Max}(0, \sum_{d=1}^{30} \sum_{i=1}^{100} \sum_{p} \text{RTAML}_{q,\,p,\,i}) \,/\, \sum_{q} (\text{Max}(0, \sum_{d=1}^{30} \sum_{i=1}^{100} \sum_{p} \text{RTAML}_{q,\,p,\,i}))$$

The above variables are defined as follows:

Variable	Unit	Definition
LARTMSAMT_{q}	$	*Load Allocated Real-Time Market Suspension Charge* – The allocated charge to QSE *q* for Market Suspension activities for the Operating Day.
$\text{MSEDCIMPAMTTOT}_{d}$	$	*Market Suspension Emergency DC Import Amount Total* – The total Market Suspension Emergency DC Import Amount charges for all QSEs for the Operating Day *d*.
MSMWAMTTOT_{d}	$	*Market Suspension Make-Whole Payment Total* – The total payment to all QSEs for Market Suspension Make-Whole Payments for the Operating Day.
MSBLTRAMTTOT_{d}	$	*Market Suspension Block Load Transfer Amount Total* – The total Market Suspension Block Load Transfer Amount for all QSEs for the Operating Day *d*.
BSSAMTTOT	$	*Black Start Service Amount QSE Total ERCOT-Wide* – The total of the payments to QSE *q* for Black Start Service (BSS) provided by all the BSS Resource represented by this QSE for the hour *h*.
RMREAMTTOT	$	*RMR Energy Amount Total* – The total of the energy cost payments to all QSEs for all RMR Units, for the hour.
RMRSBAMTTOT	$	*RMR Standby Amount Total* – The total of the Standby Payments to all QSEs for all RMR Units, for the hour.
RTMSLRS_{q}	none	*Real-Time Market Suspension Load Ratio Share* – The ratio of the QSE *q*'s Real-Time AML to the total ERCOT Real-Time AML for the 30 day period prior to the Market Suspension for which Initial Settlement has been completed.
$\text{RTAML}_{q,\,p,\,i}$	MWh	*Real-Time Adjusted Metered Load* – The sum of the AML at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval *i*.
i	none	A 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
d	none	An Operating Day.
h	none	An hour within a Market Suspension.

(b) This Market Suspension Charge shall be resettled using Transmission and/or Distribution Service Provider (TDSP)-submitted actual and estimated Load data. ERCOT-estimated data will be excluded. The most recent 30 day LRS prior to the Market Suspension event, as described in paragraph (a) above, will continue to be used to allocate Startup Costs and standby payments for RMR Units and Black Start Resources. The resettled Market Suspension Charge to each QSE for a given Operating Day is calculated as follows:

$$\text{LARTMSAMT}_{q} = (-1) * \{(\sum_{q} \sum_{r} (\text{MSSUC}_{q, r, d} + \text{MSSUCADJ}_{q, r, d}) + \sum_{h} \text{RMRSBAMTTOT} + \sum_{h} \text{BSSAMTTOT}) * \text{RTMSLRS}_{q} + [\text{MSMWAMTTOT}_{d} - \sum_{q} \sum_{r} (\text{MSSUC}_{q, r, d} + \text{MSSUCADJ}_{q, r, d}) + \text{MSEDCIMPAMTTOT}_{d} + \text{MSBLTRAMTTOT}_{d} + \sum_{h} \text{RMREAMTTOT}] * \text{AMRTSLRS}_{q, d}\}$$

Where:

$$\text{AMRTSLRS}_{q, d} = \text{Max}(0, \text{AMRTAML}_{q, d}) / \sum_{q} \text{Max}(0, \text{AMRTAML}_{q, d})$$

The above variables are defined as follows:

Variable	Unit	Definition
LARTMSAMT_{q}	\$	*Load Allocated Real-Time Market Suspension Charge* – The allocated charge to QSE *q* for Market Suspension activities for the Operating Day.
$\text{MSSUC}_{q, r, d}$	\$	*Market Suspension Startup Cost* – The Startup Costs for Resource *r* represented by QSE *q* during restart hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{MSEDCIMPAMTTOT}_{d}$	\$	*Market Suspension Emergency DC Import Amount Total* – The total Market Suspension Emergency DC Import Amount charges for all QSEs for the Operating Day *d*.
MSMWAMTTOT_{d}	\$	*Market Suspension Make-Whole Payment Total* – The total payment to all QSEs for Market Suspension Make-Whole Payments for the Operating Day.
MSBLTRAMTTOT_{d}	\$	*Market Suspension Block Load Transfer Amount Total* – The total Market Suspension Block Load Transfer Amount for all QSEs for the Operating Day *d*.
BSSAMTTOT	\$	*Black Start Service Amount QSE Total ERCOT-Wide* – The total of the payments to QSE *q* for BSS provided by all the BSS Resource represented by this QSE for the hour.
RMREAMTTOT	\$	*RMR Energy Amount Total* – The total of the energy cost payments to all QSEs for all RMR Units, for the hour.
RMRSBAMTTOT	\$	*RMR Standby Amount Total* – The total of the Standby Payments to all QSEs for all RMR Units, for the hour.

Variable	Unit	Definition
$\text{RTMSLRS}_{q,\,d}$	none	*Real-Time Market Suspension Load Ratio Share* – The ratio of the QSE *q*’s Real-Time AML to the total ERCOT Real-Time AML for the 30 day period prior to the Market Suspension for which Initial Settlement has been completed.
$\text{AMRTSLRS}_{q,\,d}$	none	*Actual Metered Real-Time Suspension Load Ratio Share* – The ratio of the QSE *q*’s actual metered Real-Time AML to the total ERCOT actual metered Real-Time AML.
$\text{AMRTAML}_{q,\,d}$	MWh	*Actual Metered Real-Time Adjusted Metered Load* – The sum of the actual metered interval data that are represented by QSE *q* for the day *d*.
q	none	A QSE.
d	none	An Operating Day during a Market Suspension event.
h	none	An hour within a Market Suspension.
r	none	A Generation Resource.

[NPRR1029: Replace paragraph (b) above with the following upon system implementation:]

(b) This Market Suspension Charge shall be resettled using Transmission and/or Distribution Service Provider (TDSP)-submitted actual and estimated Load data. ERCOT-estimated data will be excluded. The most recent 30 day LRS prior to the Market Suspension event, as described in paragraph (a) above, will continue to be used to allocate Startup Costs and standby payments for RMR Units and Black Start Resources. The resettled Market Suspension Charge to each QSE for a given Operating Day is calculated as follows:

$$\text{LARTMSAMT}_{q} = (-1) * \{(\sum_{q}\sum_{r}(\text{MSSUC}_{q,\,r,\,d} + \text{MSSUCADJ}_{q,\,r,\,d}) + \sum_{h}\text{RMRSBAMTTOT} + \sum_{h}\text{BSSAMTTOT}) * \text{RTMSLRS}_{q} + [\text{MSMWAMTTOT}_{d} - \sum_{q}\sum_{r}(\text{MSSUC}_{q,\,r,\,d} + \text{MSSUCADJ}_{q,\,r,\,d}) + \text{MSEDCIMPAMTTOT}_{d} + \text{MSBLTRAMTTOT}_{d} + \sum_{h}\text{RMREAMTTOT}] * \text{AMRTSLRS}_{q,\,d}\}$$

Where:

$$\text{AMRTSLRS}_{q,\,d} = \text{Max}(0, \text{AMRTAML}_{q,\,d} - \text{AMRTAESRML}_{q,\,d}) / \sum_{q}\text{Max}(0, \text{AMRTAML}_{q,\,d} - \text{AMRTAESRML}_{q,\,d})$$

The above variables are defined as follows:

Variable	Unit	Definition
LARTMSAMT_{q}	$	*Load Allocated Real-Time Market Suspension Charge* – The allocated charge to QSE *q* for Market Suspension activities for the Operating Day.

$MSSUC_{q,\ r,\ d}$	$	*Market Suspension Startup Cost* – The Startup Costs for Resource *r* represented by QSE *q* during restart hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MSEDCIMPAMTTOT_{d}$	$	*Market Suspension Emergency DC Import Amount Total* – The total Market Suspension Emergency DC Import Amount charges for all QSEs for the Operating Day *d*.
$MSMWAMTTOT_{d}$	$	*Market Suspension Make-Whole Payment Total* – The total payment to all QSEs for Market Suspension Make-Whole Payments for the Operating Day.
$MSBLTRAMTTOT_{d}$	$	*Market Suspension Block Load Transfer Amount Total* – The total Market Suspension Block Load Transfer Amount for all QSEs for the Operating Day *d*.
BSSAMTTOT	$	*Black Start Service Amount QSE Total ERCOT-Wide* – The total of the payments to QSE *q* for BSS provided by all the BSS Resource represented by this QSE for the hour.
RMREAMTTOT	$	*RMR Energy Amount Total* – The total of the energy cost payments to all QSEs for all RMR Units, for the hour.
RMRSBAMTTOT	$	*RMR Standby Amount Total* – The total of the Standby Payments to all QSEs for all RMR Units, for the hour.
$RTMSLRS_{q,\ d}$	none	*Real-Time Market Suspension Load Ratio Share* – The ratio of the QSE *q*'s Real-Time AML to the total ERCOT Real-Time AML for the 30 day period prior to the Market Suspension for which Initial Settlement has been completed.
$AMRTSLRS_{q,\ d}$	none	*Actual Metered Real-Time Suspension Load Ratio Share* – The ratio of the QSE *q*'s actual metered Real-Time AML to the total ERCOT actual metered Real-Time AML.
$AMRTAML_{q,\ d}$	MWh	*Actual Metered Real-Time Adjusted Metered Load* – The sum of the actual metered Load represented by QSE *q* for the day *d*.
$AMRTAESRML_{q,\ d}$	MWh	*Actual Metered Real-Time Adjusted ESR Metered Load* – The sum of the ESR actual metered Load represented by QSE *q* for the day *d*. Where the ESR actual metered Load represents the ESR Load as measured by Metered Energy for Energy Storage Resource Load at Bus (MEBR), as described in Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node.
q	none	A QSE.
d	none	An Operating Day during a Market Suspension event.
h	none	An hour within a Market Suspension.
r	none	A Generation Resource or ESR.

25.5.6 Market Suspension Data Submissions

(1) Any data submissions provided by the TDSP, Meter Reading Entity (MRE), or a QSE representing a Generation Resource required or requested by ERCOT due to a Market Suspension shall be filed within five months of the Market Restart, including but not limited to:

(a) Generation data;

(b) Load data;

(c) Actual price paid for delivered natural gas, fuel oil, or another fuel; and

(d) Costs associated with the transport or delivery of fuel.

[NPRR1029: Insert paragraph (2) below upon system implementation:]

(2) Any QSE representing an ESR may submit the following information to ERCOT within five months of the Market Restart for ERCOT's use in calculating the QSE's payment pursuant to Section 25.5.2, Market Suspension Make-Whole Payment:

(a) Actual variable O&M rate incurred during the Market Suspension period in lieu of the Standard Operations and Maintenance Cost (STOM);

(b) The electricity cost incurred prior to a Market Suspension for any net amount of discharge of the battery during the Market Suspension period, if the ESR's state of charge at the end of the Market Suspension is less than the state of charge at the beginning of the period. The electricity cost incurred to charge the battery prior to a Market Suspension may include the cost of serving any auxiliary Load not measured with the settlement meters. The following information must be provided to support recovery of these costs:

(i) Battery state of charge prior to Market Suspension;

(ii) Battery state of charge at the end of the Market Suspension;

(iii) Prices paid to charge the battery for the MWh difference between (i) and (ii) above.

25.5.7 Invoice Payment and Charges Schedule

(1) To the extent feasible, ERCOT will calculate and pay the Market Suspension Make-Whole Payment in accordance with Section 25.5.2, Market Suspension Make-Whole Payment, to each QSE during a Market Suspension Event.

(2) Beginning five Business Days after the Market Restart, ERCOT will issue initial daily Invoices each Business Day for each Operating Day of the Market Suspension.

(3) ERCOT shall send a Market Notice and post a Settlement Calendar for the Operating Days of the Market Suspension no later than five Business Days after the Market Restart.

(4) ERCOT shall adjust the initial Invoice with a final Invoice that shall be issued 55 days after the initial Invoice was issued unless that day is not a Business Day. If the 55th day is not a Business Day, then ERCOT shall issue the final Invoice on the first Business Day after the 55th day.

(5) ERCOT shall true up the final Invoice with a true up Invoice that shall be issued 180 days after the initial Invoice was issued unless that day is not a Business Day. If the 180th day is not a Business Day, then ERCOT shall issue the true up Invoice on the first Business Day after the 180th day.

(6) Payments due to and from ERCOT for Settlement Invoices related to a Market Suspension shall be done in accordance with Section 9.7, Payment Process for the Settlement Invoices.

25.5.8 RMR Settlements

(1) After ERCOT resumes Settlement of the RTM following a Market Suspension, RMR Units shall be settled in accordance with Section 6.6.6.1, RMR Standby Payment, and Section 6.6.6.2, RMR Payment for Energy, except that, before actual costs are submitted, the FIP may be replaced with the Market Suspension Average Fuel Index Price (MSAVGFIP), as described in Section 25.5.2, Market Suspension Make-Whole Payment.

25.6 ERCOT Retail Operations

25.6.1 ERCOT Retail Operations Market Suspension Procedures

(1) Once ERCOT has declared a Market Suspension, Market Participants shall follow the processes outlined in Retail Market Guide Section 7.10, Extended Unplanned Outage, and in applicable supplementary documentation.

(2) Following a declaration of Market Suspension, when practicable, ERCOT shall issue a Market Notice informing Market Participants of when ERCOT expects to resume processing retail market transactions. This may not be contemporaneous with the restart of other ERCOT market-related functions.

(3) As soon as practicable, following the issuance of the Market Notice, ERCOT shall conduct one or more retail market conference calls. The calls are intended to allow ERCOT and Market Participants to identify and communicate ongoing issues and system constraints, coordinate processes for staging, ordering and submission of back-logged retail market transactions, and identify impacts on related processes such as flight testing.

ERCOT Nodal Protocols

Section 26: Securitization Default Charges

June 1, 2022

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26 SECURITIZATION DEFAULT CHARGES

26.1 Overview

(1) This section establishes processes for the assessment of Securitization Default Charges and Securitization Default Charge credit requirements.

26.2 Securitization Default Charges

(1) ERCOT shall issue Invoices to Qualified Scheduling Entities (QSEs) and Congestion Revenue Right (CRR) Account Holders to collect the monthly amount determined by ERCOT to be necessary to repay the Securitization Default Balance. ERCOT may assess Securitization Default Charges over a period of up to 30 years.

(2) Each Counter-Party's share of the Securitization Default Charge for a month is calculated using the best available Settlement data for the most recent month for which ERCOT has posted Final Settlement data for all Operating Days in the month (referred to below as "the reference month"), as follows:

$$\mathbf{SDCRSCP}_{cp} = \mathbf{TSDCMA} * \mathbf{SDCMMARS}_{cp}$$

Where:

$$\text{SDCMMARS}_{cp} = \text{SDCMMA}_{cp} / \text{SDCMMATOT}$$

$$\begin{aligned}\text{SDCMMA}_{cp} = \text{Max}\ \{ & \textstyle\sum_{mp} (\text{SDCRTMG}_{mp} + \text{SDCRTDCIMP}_{mp}), \\ & \textstyle\sum_{mp} (\text{SDCRTAML}_{mp} + \text{SDCWSLTOT}_{mp}), \\ & \textstyle\sum_{mp} \text{SDCRTQQES}_{mp}, \\ & \textstyle\sum_{mp} \text{SDCRTQQEP}_{mp}, \\ & \textstyle\sum_{mp} \text{SDCDAES}_{mp}, \\ & \textstyle\sum_{mp} \text{SDCDAEP}_{mp}, \\ & \textstyle\sum_{mp} (\text{SDCRTOBL}_{mp} + \text{SDCRTOBLLO}_{mp}), \\ & \textstyle\sum_{mp} (\text{SDCDAOPT}_{mp} + \text{SDCDAOBL}_{mp} + \text{SDCOPTS}_{mp} + \\ & \quad \text{SDCOBLS}_{mp}), \\ & \textstyle\sum_{mp} (\text{SDCOPTP}_{mp} + \text{SDCOBLP}_{mp})\}\end{aligned}$$

$$\text{SDCMMATOT} = \textstyle\sum_{cp} (\text{SDCMMA}_{cp})$$

Where:

$\text{SDCRTMG}_{mp} = \sum_{r, p, i} (\text{RTMG}_{mp, r, p, i})$, excluding RTMG for Reliability Must-Run (RMR) Resources and RTMG in Reliability Unit Commitment (RUC)-Committed Intervals for RUC-committed Resources

$\text{SDCRTDCIMP}_{mp} = \sum_{p, i} (\text{RTDCIMP}_{mp, p, i}) / 4$

$\text{SDCRTAML}_{mp} = \max(0, \sum_{p, i} (\text{RTAML}_{mp, p, i}))$

$\text{SDCRTQQES}_{mp} = \sum_{p, i} (\text{RTQQES}_{mp, p, i}) / 4$

$\text{SDCRTQQEP}_{mp} = \sum_{p, i} (\text{RTQQEP}_{mp, p, i}) / 4$

$\text{SDCDAES}_{mp} = \sum_{p, h} (\text{DAES}_{mp, p, h})$

$\text{SDCDAEP}_{mp} = \sum_{p, h} (\text{DAEP}_{mp, p, h})$

$\text{SDCRTOBL}_{mp} = \sum_{(j, k), h} (\text{RTOBL}_{mp, (j, k), h})$

$\text{SDCRTOBLLO}_{mp} = \sum_{(j, k), h} (\text{RTOBLLO}_{mp, (j, k), h})$

$\text{SDCDAOPT}_{mp} = \sum_{(j, k), h} (\text{OPT}_{mp, (j, k), h})$

$\text{SDCDAOBL}_{mp} = \sum_{(j, k), h} (\text{DAOBL}_{mp, (j, k), h})$

$\text{SDCOPTS}_{mp} = \sum_{(j, k), h} (\text{OPTS}_{mp, (j, k), h})$

$\text{SDCOBLS}_{mp} = \sum_{(j, k), h} (\text{OBLS}_{mp, (j, k), h})$

$\text{SDCOPTP}_{mp} = \sum_{(j, k), h} (\text{OPTP}_{mp, j, h})$

$\text{SDCOBLP}_{mp} = \sum_{(j, k), h} (\text{OBLP}_{mp, (j, k), h})$

$\text{SDCWSLTOT}_{mp} = (-1) * \sum_{r, b} (\text{MEBL}_{mp, r, b})$

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.

Variable	Unit	Definition
SDCMMATOT	MWh	*Securitization Default Charge Maximum MWh Activity Total*—The sum of all Counter-Party's Maximum MWh Activity.
RTMG $_{mp, p, r, i}$	MWh	*Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTMG $_{mp}$	MWh	*Securitization Default Charge Real-Time Metered Generation per Market Participant*—The monthly sum in the reference month of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTDCIMP $_{mp, p, i}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTDCIMP $_{mp}$	MW	*Securitization Default Charge Real-Time DC Import per Market Participant*—The monthly sum in the reference month of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party.
RTAML $_{mp, p, i}$	MWh	*Real-Time Adjusted Metered Load per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML) at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTAML $_{mp}$	MWh	*Securitization Default Charge Real-Time Adjusted Metered Load per Market Participant*—The monthly sum in the reference month of the AML represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQES $_{mp, p, i}$	MW	*QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTQQES $_{mp}$	MWh	*Securitization Default Charge QSE-to-QSE Energy Sale per Market Participant*—The monthly sum in the reference month of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQEP $_{mp, p, i}$	MW	*QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
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.

Variable	**Unit**	**Definition**
$SDCDAES_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Sale per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party.
$DAEP_{mp,\,p,\,h}$	MW	*Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared DAM Energy Bids at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.
$SDCDAEP_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Purchase per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s cleared DAM Energy Bids, where the Market Participant is a QSE assigned to the registered Counter-Party.
$RTOBL_{mp,\,(j,\,k),\,h}$	MW	*Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE.
$SDCRTOBL_{mp}$	MWh	*Securitization Default Charge Real-Time Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party.
$RTOBLLO_{q,\,(j,\,k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
$SDCRTOBLLO_{q,\,(j,\,k)}$	MW	*Securitization Default Charge Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The monthly total in the reference month of Market Participant *mp*'s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party.
$OPT_{mp,\,(j,\,k),\,h}$	MW	*Day-Ahead Option per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
$SDCDAOPT_{mp}$	MWh	*Securitization Default Charge Day-Ahead Option per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
$DAOBL_{mp,\,(j,\,k),\,h}$	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.

Variable	**Unit**	**Definition**
OPTS $_{mp, (j, k), a, h}$	MW	*PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTS $_{mp}$	MWh	*Securitization Default Charge PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLS $_{mp, (j, k), a, h}$	MW	*PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOBLS $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTP $_{mp, (j, k), a, h}$	MW	*PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTP $_{mp}$	MWh	*Securitization Default Charge PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLP $_{mp, (j, k), a, h}$	MW	*PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOBLP $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
SDCWSLTOT $_{mp}$	MWh	*Securitization Default Charge Metered Energy for Wholesale Storage Load at bus per Market Participant*—The monthly sum in the reference month of Market Participant *mp*'s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL.
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.

Variable	Unit	Definition
mp	none	A Market Participant that is a QSE or CRR Account Holder with activity in the reference month, except for a Market Participant exempt from Securitization Default Charges pursuant to the Final Order entered by the Public Utility Commission of Texas (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.

26.3 Miscellaneous Invoices for Securitization Default Charges

(1) ERCOT shall prepare miscellaneous Invoices for Securitization Default Charges on a monthly basis, as specified in Section 9.1.2, Settlement Calendar, on the seventh Business Day of a month. Unless expressly stated otherwise, the publication of the miscellaneous Invoices can occur as late as 2400 on the scheduled publication date. The Market Participant to whom the Invoice is addressed (Invoice Recipient) is a payor.

(2) Each Invoice Recipient shall pay any debit shown on the miscellaneous Invoice for Securitization Default Charges on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit.

(3) ERCOT shall post miscellaneous Invoices for Securitization Default Charges on the Market Information System (MIS) Certified Area. The Invoice Recipient is responsible for accessing the Invoices on the MIS Certified Area once posted by ERCOT, as described in Section 9.1.3, Settlement Statement and Invoice Access.

(4) All disputes for miscellaneous Invoices related to the Securitization Default Charges shall follow the process described in Section 9.14, Settlement and Billing Dispute Process.

26.3.1 Payment Process for Miscellaneous Invoices for Securitization Default Charges

(1) Payments for miscellaneous Invoices for Securitization Default Charges are due on a Business Day and Bank Business Day basis in a process detailed below.

26.3.1.1 Invoice Recipient Payment to ERCOT for Miscellaneous Invoices for Securitization Default Charges

(1) The payment due date and time for the miscellaneous Invoices for Securitization Default Charges, with funds owed by an Invoice Recipient, is 1700 on the fifth Bank Business Day after the miscellaneous Invoice date, unless the fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All miscellaneous Invoices for Securitization Default Charges due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars (USDs) by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal) on or before the payment due date. EFTs must be with U.S. banks only.

(3) Miscellaneous Invoices that are issued for Securitization Default Charges are distinct from other Invoices issued by ERCOT and must be paid by an EFT that is separate from any other Invoice. An Invoice Recipient may not net amounts owing on a miscellaneous Invoice for Securitization Default Charges with any other funds due to or from ERCOT.

(4) Payments for Securitization Default Charges must be made to the account listed on the invoice. If payment is not made to the correct account, the payment will be rejected. Failure to remit funds to the correct account may result in a Payment Breach. The payment remark must include the invoice number.

26.3.1.2 Insufficient Payments by Miscellaneous Invoice Recipients for Securitization Default Charges

(1) If an Invoice Recipient owing funds does not pay its miscellaneous Invoice for Securitization Default Charges in full (short-pay) by the payment due date and time set forth in Section 26.3.1.1, Invoice Recipient Payment to ERCOT for Miscellaneous

Invoices for Securitization Default Charges, ERCOT shall follow the procedure set forth below:

(a) ERCOT shall draw on any available Securitization Default Charge escrow deposit by the short-paying miscellaneous Invoice Recipient.

(b) If available Securitization Default Charge escrow deposits are insufficient to cover the short-paid amount, ERCOT may utilize Financial Security held with respect to other ERCOT market activities as determined under Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure. ERCOT may not utilize Securitization Uplift Charge escrow deposits to cover short-pays of miscellaneous Invoices for Securitization Default Charges.

(c) In the event that an Invoice Recipient short-pays:

(i) Both a miscellaneous Invoice for Securitization Default Charges and a Securitization Uplift Charge Initial Invoice; or

(ii) One or both of the above securitization Invoices as well as any other ERCOT Invoice;

and it is necessary to utilize Financial Security held with respect to other ERCOT market activities, funds drawn from Financial Security will be allocated first to cover short-pays of Invoices for non-securitization activity. Any remaining Financial Security will be allocated pro rata on the basis of unpaid Invoice amounts to Securitization Uplift Charge Initial Invoices and miscellaneous Invoices for Securitization Default Charges.

(d) Regardless of whether ERCOT's draw on an available Securitization Default Charge escrow deposit or other Financial Security under paragraphs (a) through (c) above is sufficient to cover the amount owed by a Market Participant for a miscellaneous Invoice for Securitization Default Charges, a Market Participant's failure to pay the miscellaneous Invoice by the payment due date and time will still be deemed a Payment Breach under Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(e) If an amount owed to ERCOT for a miscellaneous Invoice for Securitization Default Charges cannot be fully recovered from a short-paying Market Participant by drawing upon available Securitization Default Charge escrow deposits, available Financial Security held with respect to other ERCOT market activities, or taking other action against the Market Participant to recover the amount owed, the remaining short payment amount will be taken into consideration in ERCOT's next evaluation of the Total Securitization Default Charge Monthly Amount (TSDCMA) performed pursuant to paragraph (4) of Section 26.2, Securitization Default Charges, that occurs after the short payment.

(f) Any action taken by ERCOT under this Section does not relieve or otherwise excuse the short-paying Market Participant of its obligation to fully pay all outstanding financial obligations to ERCOT, including is obligation to fully pay all miscellaneous Invoices for Securitization Default Charges.

[NPRR1103: Replace Sections 26.3, 26.3.1, 26.3.1.1, and 26.3.1.2 above with the following upon system implementation:]

26.3 Securitization Default Charge Invoices

(1) ERCOT shall prepare Securitization Default Charge Invoices on a monthly basis, as specified in Section 9.1.2, Settlement Calendar, on the seventh Business Day of a month. Unless expressly stated otherwise, the publication of the Securitization Default Charge Invoices can occur as late as 2400 on the scheduled publication date. The Market Participant to whom the Invoice is addressed (Invoice Recipient) is a payor.

(2) Each Invoice Recipient shall pay any debit shown on the Securitization Default Charge Invoice on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit.

(3) ERCOT shall post the Securitization Default Charge Invoice on the MIS Certified Area. The Invoice Recipient is responsible for accessing the Securitization Default Charge Invoice on the MIS Certified Area once posted by ERCOT, as described in Section 9.1.3, Settlement Statement and Invoice Access.

(4) The Securitization Default Charge Invoice must comply with the Settlement payment convention, as set forth in Section 9.1.5, Settlement Payment Convention.

(5) Securitization Default Charge Invoices must contain the following information:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Owed– the charge owed by an Invoice Recipient;

(d) Time Period – the reference month for which the Securitization Default Charge Invoice is generated;

(e) Run Date – the date on which the Invoice was created and published;

(f) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes;

(g) Payment Date and Time – the date and time the Invoice amounts must be paid;

(h) Remittance Information Details – details including the account number, bank name, and electronic transfer instructions of the ERCOT Securitization Default Charge account to which any amounts owed by the Invoice Recipient are to be paid; and

(i) Overdue Terms – the terms that would apply if the payments were received late.

(6) All disputes for Securitization Default Charge Invoices shall follow the process described in Section 9.14, Settlement and Billing Dispute Process.

26.3.1 Payment Process for Securitization Default Charge Invoices

(1) Payments for Securitization Default Charge Invoices are due on a Business Day and Bank Business Day basis in a process detailed below.

26.3.1.1 Invoice Recipient Payment to ERCOT for Securitization Default Charge Invoices

(1) The payment due date and time for Securitization Default Charge Invoices, with funds owed by an Invoice Recipient, is 1700 on the fifth Bank Business Day after the Securitization Default Charge Invoice date, unless fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All Securitization Default Charge Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars (USDs) by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal) on or before the payment due date. EFTs must be with U.S. banks only.

(3) Securitization Default Charge Invoices are distinct from other Invoices issued by ERCOT and must be paid by an EFT that is separate from any other Invoice. An Invoice Recipient may not net amounts owing on a Securitization Default Charge Invoice with any other funds due to or from ERCOT.

(4) Payments for Securitization Default Charges must be made to the account listed on the Invoice. If payment is not made to the correct account, the payment will be rejected. Failure to remit funds to the correct account may result in a Payment Breach. The payment remark must include the Invoice number.

26.3.1.2 Insufficient Payments by Invoice Recipients for Securitization Default Charge Invoices

(1) If an Invoice Recipient owing funds does not pay its Securitization Default Charge Invoice in full (short-pay) by the payment due date and time set forth in Section 26.3.1.1, Invoice

Recipient Payment to ERCOT for Securitization Default Charge Invoices, ERCOT shall follow the procedure set forth below:

(a) ERCOT shall draw on any available Securitization Default Charge escrow deposits by the Invoice Recipient.

(b) If available Securitization Default Charge escrow deposits are insufficient to cover the short-paid amount, ERCOT will utilize Financial Security held with respect to other ERCOT market activities as determined in Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure. ERCOT may not utilize Securitization Uplift Charge escrow deposits to cover short-pays of Securitization Default Charges.

(c) In the event that an Invoice Recipient short-pays:

  (i) Both a Securitization Default Charge Invoice and a Securitization Uplift Charge Initial Invoice, or;

  (ii) One or both of the above securitization Invoices as well as any other ERCOT Invoice,

and it is necessary to utilize Financial Security held with respect to other ERCOT market activities, funds drawn from Financial Security will be allocated first to cover short-pays of Invoices for non-securitization activity. Any remaining Financial Security will be allocated pro rata on the basis of unpaid Invoice amounts to Securitization Uplift Charge Initial Invoices and Securitization Default Charge Invoices.

(d) Regardless of whether ERCOT's draw on available Securitization Default Charge escrow deposits or other Financial Security under paragraphs (a) through (c) above is sufficient to cover the amount owed by a Market Participant for a Securitization Default Charge Invoice, a Market Participant's failure to pay the Invoice by the payment due date and time will still be deemed a Payment Breach under Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(e) If an amount owed to ERCOT for a Securitization Default Charge Invoice cannot be fully recovered from a short-paying Market Participant by drawing upon available Securitization Default Charge escrow deposits, available Financial Security held with respect to other ERCOT market activities, or taking other action against the Market Participant to recover the amount owed, the remaining short payment amount will be taken into consideration in ERCOT's next evaluation of the Total Securitization Default Charge Monthly Amount performed pursuant to paragraph (4) of Section 26.2, Securitization Default Charges, that occurs after the short payment.

(f) Any action taken by under this Section does not relieve or otherwise excuse the short paying Market Participant of its obligation to fully pay all outstanding financial obligations to ERCOT, including is obligation to fully pay all Securitization Default Charge Invoices.

26.4 Securitization Default Charge Supporting Data Reporting

(1) On a monthly basis, ERCOT shall post the following information on the Market Information System (MIS) Certified Area:

(a) Securitization Default Charge Maximum MWh Activity (SDCMMA);

(b) Securitization Default Charge Maximum MWh Activity Total (SDCMMATOT);

(c) Securitization Default Charge Maximum MWh Activity Ratio Share (SDCMMARS); and

(d) Counter-Party level components of the SDCMMA calculation, as defined in paragraph (2) of Section 26.2, Securitization Default Charges.

(2) ERCOT shall post separate reports containing Initial and Final Settlement data as such data becomes available.

[NPRR1103: Replace Section 26.4 above with the following upon system implementation:]

26.4 Securitization Default Charge Supporting Data Reporting

(1) On a monthly basis, ERCOT shall post the following information on the Market Information System (MIS) Certified Area:

(a) Securitization Default Charge Maximum MWh Activity (SDCMMA);

(b) Securitization Default Charge Maximum MWh Activity Total (SDCMMATOT);

(c) Securitization Default Charge Maximum MWh Activity Ratio Share (SDCMMARS): and

(d) Counter-Party level components of the SDCMMA calculation, as defined in paragraph (2) of Section 26.2, Securitization Default Charge.

(2) ERCOT shall post a report containing Initial Settlement data as such data becomes available. The report shall be updated with Final Settlement data as such data becomes available.

26.5 Securitization Default Charge Escrow Deposit Requirements

26.5.1 Securitization Default Charge Escrow

(1) The term “Securitization Default Charge escrow deposit” means the amount required to be deposited with ERCOT in the form of cash or an unconditional, irrevocable letter of

credit to be held in escrow for a Market Participant's obligation to pay Securitization Default Charges.

(2) Although ERCOT is the servicer for the assessment and collection of Securitization Default Charges, by providing escrow deposits pursuant to this Section each Counter-Party grants the Texas Electric Market Stabilization Funding M LLC (TEMSFM) a secured interest in Securitization Default Charge escrow deposits to secure its obligation to pay the same.

(3) The security interest of TEMSFM is perfected upon a Counter-Party's deposit of cash or a letter of credit with ERCOT pursuant to this Section.

26.5.2 ERCOT Securitization Default Charge Credit Requirements for Counter-Parties

(1) A Counter-Party must, at all times, maintain its Securitization Default Charge escrow deposit at or above the amount of its Securitization Default Charge Credit Exposure (SDCCE). Each Counter-Party shall maintain any required Securitization Default Charge escrow deposit in a form acceptable to ERCOT in its sole discretion pursuant to Section 26.5.3, Means of Satisfying Securitization Default Charge Credit Requirements.

(2) If at any time a Counter-Party does not meet ERCOT's SDCCE requirements, then the Counter-Party will be considered to be in Payment Breach and ERCOT may suspend the Counter-Party's rights under these Protocols until it meets the SDCCE requirements.

(3) ERCOT's failure to suspend a Counter-Party's rights on any particular occasion does not prevent ERCOT from suspending those rights on any subsequent occasion, including a Congestion Revenue Right (CRR) Account Holder's ability to bid on future CRRs or a Qualified Scheduling Entity's (QSE's) ability to bid in the Day-Ahead Market (DAM).

26.5.3 Means of Satisfying Securitization Default Charge Credit Requirements

(1) If a Counter-Party is required to provide a Securitization Default Charge escrow deposit, then it may do so through one or both of the following means:

    (a) The Counter-Party may give an unconditional, irrevocable letter of credit naming TEMSFM as the beneficiary. ERCOT or the TEMSFM may reject the letter of credit if the issuer is unacceptable to ERCOT or TEMSFM or if the conditions under which ERCOT or TEMSFM may draw against the letter of credit are unacceptable to ERCOT or TEMSFM.

    (b) All letters of credit must be drawn on a US domestic bank or a domestic office of a foreign bank, and must meet the requirements in Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

    (c) Letters of credit held as Securitization Default Charge escrow deposits are subject to letter of credit issuer limits as specified in paragraph (1) of Section 16.11.3.

(d) The Counter-Party may deposit cash with TEMSFM through ERCOT with the understanding that ERCOT may draw part or all of the deposited cash to satisfy any overdue payments owed by the Counter-Party to ERCOT for Securitization Default Charges. The cash deposits may bear interest payable directly to the Counter-Party, but any such arrangements may not restrict ERCOT's immediate access to the cash.

(i) Interest on cash deposited pursuant to this Section will be calculated based on Counter-Party average cash deposit balance. Interest is not paid on a cash deposit balance held by TEMSFM where, in accordance with paragraph (4) of Section 16.11.7, Release of Market Participant's Financial Security Requirement, the Counter-Party's Standard Form Market Participant Agreement has been terminated and ERCOT has determined that no obligations for Securitization Default Charges remain owing or will become due and payable.

(ii) Once per year, ERCOT will return interest earned on a Counter-Party's cash deposits pursuant to this Section to the Counter-Party.

(2) Securitization Default Charge escrow deposits are held solely for the purpose of collateralizing SDCCE and shall not be used for any other purpose. They are independent of and in addition to any other Financial Security obligations of the Counter-Party arising under Section 16.11, Financial Security for Counter-Parties, or Section 27, Securitization Uplift Charges.

(3) Funds provided for Securitization Default Charge escrow deposits must be made to the account designated for Securitization Default Charge escrow deposits. If a payment is not made to the correct account, ERCOT is not responsible for transferring the funds to the correct escrow deposit account. Failure to remit funds to the correct account by the date and time required will result in a Late Payment and/or Payment Breach.

(4) A Counter-Party with excess cash held with respect to one or more Securitization Default Charge escrow deposit requirements may request ERCOT to return some or all of the excess cash to the Counter-Party.

(5) Securitization Default Charge escrow deposits will not be used to pay periodic Securitization Default Charge Invoices unless there is an insufficient payment by the Invoice Recipient, in accordance with Section 26.3.1.2, Insufficient Payments by Miscellaneous Invoice Recipients for Securitization Default Charges.

(6) Securitization Default Charge escrow deposits in excess of the SDCCE requirement shall not be used to cover insufficient payments of Settlement Invoices for ERCOT market activities under Section 9.19, Partial Payments by Invoice Recipients, or requests for additional Financial Security made in accordance with paragraph (6) of Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT. Further, Securitization Default Charge escrow deposits in excess of the SDCCE shall not

be used to cover insufficient payments of Invoices or escrow deposit requirements under Section 27.

26.5.4 Determination of Securitization Default Charge Credit Exposure for a Counter-Party

(1) For each Counter-Party, ERCOT shall calculate the SDCCE as follows:

$$\text{SDCCE}_{cp} = \text{SDCMMARS}_{cp,\, rm} * \sum_{fmd=1}^{nfmd} (\text{TSDCMA}_{fmd})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
SDCCE $_{cp}$	$	*Securitization Default Charge Credit Exposure* – Estimated credit exposure for each Counter-Party related to Securitization Default Charges.
SDCMMARS $_{cp,\, rm}$	None	*Securitization Default Charge Maximum MWh Activity Ratio Share* – The Counter-Party's pro rata share of Securitization Default Charge Maximum MWh Activity in the most recent available reference month *rm* based on Initial Settlements.
TSDCMA	$	*Total Securitization Default Charge Monthly Amount* – The amount ERCOT determines must be collected for the month in order to timely repay the Securitization Default Balance.
cp	none	A registered Counter-Party.
rm	none	*Reference Month* – most recent available operating month
fmd	None	*Forward Month* – a month from Securitization Default Charge forward months
nfmd	None	*Number of forward months* – total number of forward months Securitization Default Charge is extrapolated

The above parameters are defined as follows:

Parameter	**Unit**	**Current Value**
nfmd	Months	4

26.5.5 Monitoring of a Counter-Party's Securitization Default Charge Credit Exposure by ERCOT

(1) Pursuant to Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT, ERCOT shall monitor the credit exposure of each Counter-Party, including SDCCE.

(2) A Counter-Party is responsible at all times for maintaining Securitization Default Charge escrow deposits in an amount equal to or greater than that Counter-Party's SDCCE.

(3) ERCOT shall promptly notify each Counter-Party of the need to increase its Securitization Default Charge escrow deposit and allow the Counter-Party time, as provided in paragraph (5) below, to provide additional Securitization Default Charge escrow deposits to maintain compliance with this Section.

(4) ERCOT may suspend a Counter-Party when that Counter-Party's SDCCE, as defined in Section 26.5.4, Determination of Securitization Default Charge Credit Exposure for a Counter-Party, exceeds 100% of its Securitization Default Charge escrow deposit. Any failure by ERCOT to send a Notice as set forth in this Section does not relieve the Counter-Party from the obligation to maintain appropriate Securitization Default Charge escrow deposits in amounts equal to or greater than that Counter-Party's SDCCE.

(5) To the extent that a Counter-Party fails to maintain Securitization Default Charge escrow deposit in amounts equal to or greater than its SDCCE, each as defined in Section 26.5.4:

(a) ERCOT shall promptly notify the Counter-Party of the amount by which its Securitization Default Charge escrow deposit must be increased and allow it:

(i) Until 1500 on the second Bank Business Day from the date on which ERCOT delivered the notice to increase its Securitization Default Charge escrow deposit if ERCOT delivered its Notice before 1500; or

(ii) Until 1700 on the second Bank Business Day from the date on which ERCOT delivered notification to increase its Securitization Default Charge escrow deposit if ERCOT delivered its notice after 1500 but prior to 1700.

(b) If the Counter-Party does not increase its Securitization Default Charge escrow deposit to the required amount by the specified time, ERCOT may utilize Financial Security held with respect to other ERCOT market activities as determined under Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure, up to the amount of the Securitization Default Charge escrow deposit shortfall.

(c) In the event that a Counter-Party is required to increase both its Securitization Default Charge escrow deposit and its Securitization Uplift Charge escrow deposit, and ERCOT utilizes the Counter-Party's Financial Security, available Financial Security funds will be allocated on a pro rata basis to Securitization Uplift Charge and Securitization Default Charge escrow deposit requirements.

(d) ERCOT shall notify the QSE's Authorized Representative(s) and Credit Contact if it has not received the required security by 1530 on the Bank Business Day on which the security was due; however, failure to notify the Counter-Party's representatives or credit contacts that the required security was not received does not prevent ERCOT from exercising any of its other rights under this Section.

(e) ERCOT is not required to make any payment to a Counter-Party unless and until the Counter-Party increases its Securitization Default Charge escrow deposit to an amount equal to or greater than that Counter-Party's SDCCE. The payments that ERCOT may not make to a Counter-Party include Invoice receipts, CRR revenues, CRR credits, reimbursements for short payments, and any other reimbursements or credits under any other agreement between the Market Participant and ERCOT. ERCOT may retain all such amounts until the Counter-Party has fully discharged all payment obligations owed to ERCOT under the Agreement, other agreements, and these Protocols.

(6) If a Counter-Party increases its Securitization Default Charge escrow deposit as required by ERCOT by the deadline in paragraph (5)(a) above, then ERCOT shall release any payments held, providing the Counter-Party has no other payment deficiencies with respect to any other activity under these Protocols.

26.5.6 Payment Breach and Late Payments by Market Participants

(1) In the event of a Payment Breach or Late Payment by a Market Participant with respect to Securitization Default Charge Invoices or required Securitization Default Charge escrow deposits, all remedies specified in Section 16.11.6, Payment Breach and Late Payments by Market Participants, are applicable.

26.5.7 Release of Market Participant's Securitization Default Charge Escrow Deposit Requirement

(1) ERCOT shall continue to retain all Securitization Default Charge escrow deposits to cover, if necessary, potential future obligations for Securitization Default Charges.

(2) Upon ERCOT's sole determination that all potential Securitization Default Charge Invoices have been paid, ERCOT shall return or release any remaining Securitization Default Charge escrow deposits to a terminated Market Participant.

ERCOT Nodal Protocols

Section 27: Securitization Uplift Charges

July 15, 2022

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27 SECURITIZATION UPLIFT CHARGES

27.1 Overview

(1) This Section establishes processes for the assessment of Securitization Uplift Charges and Securitization Uplift Charge credit requirements.

27.2 Changes Involving Securitization Uplift Charge Opt-Out Entities

(1) For purposes of the calculation of Securitization Uplift Charges pursuant to Section 27.3, Securitization Uplift Charge, a change to the Retail Electric Provider (REP) of a Securitization Uplift Charge Opt-Out Entity that is a transmission-voltage Customer of a REP will be reflected upon completion of the Switch Request for that transmission-voltage Customer. A REP is responsible for maintaining current records of transmission-voltage Customers that are Securitization Uplift Charge Opt-Out Entities.

(2) ERCOT, in its discretion, may seek information from a REP or Transmission and/or Distribution Service Provider (TDSP) regarding a Securitization Uplift Charge Opt-Out Entity that is a transmission-voltage Customer of a REP if ERCOT has reason to believe that there has been a change of transmission-voltage Customer at an Electric Service Identifier (ESI ID) associated with the Securitization Uplift Charge Opt-Out Entity. ERCOT may seek relief from the Public Utility Commission of Texas (PUCT) if ERCOT has reason to believe that there has been a change that disqualifies an ESI ID or the transmission-voltage Customer from continued treatment as a Securitization Uplift Charge Opt-Out Entity.

(3) If a Securitization Uplift Charge Opt-Out Entity is an Electric Cooperative (EC), Municipally Owned Utility (MOU), or river authority, but is not registered with ERCOT as a Load Serving Entity (LSE), and registers with ERCOT as an LSE or changes its LSE, then ERCOT may, as part of the LSE registration process, request that the Market Participant notify ERCOT of the Market Participant's status as a Securitization Uplift Charge Opt-Out Entity. The failure of an EC, MOU, or river authority to notify ERCOT of its Securitization Uplift Charge Opt-Out Entity status in the LSE registration process will not impact the Market Participant's status as a Securitization Uplift Charge Opt-Out Entity.

(4) A Securitization Uplift Charge Opt-Out Entity that is a REP must notify ERCOT within five Business Days of filing an application to amend its REP certification status or option type with the PUCT.

(5) A Securitization Uplift Charge Opt-Out Entity that is a REP must notify ERCOT within five Business Days of the REP becoming the Competitive Retailer (CR) of Record for a Customer that is not an affiliate of the REP or that does not have the same corporate parent of the REP.

(6) Subject to paragraph (2) above, if a transmission-voltage Customer of a REP is a Securitization Uplift Charge Opt-Out Entity, the only ESI IDs associated with the transmission-voltage Customer that will be included in the Adjusted Metered Load (AML) adjustments for Securitization Uplift Charge Opt-Out Entities made under Section 27.3 are the specific ESI IDs included in opt-out notifications filed by the opt-out deadline in PUCT Project No. 52364, Proceeding for Eligible Entities to File an Opt Out Pursuant to PURA § 39.653(d) and for Load-Serving Entities to File Documentation of Exposure to Costs Pursuant to the Debt Obligation Order in Docket No. 52322.

27.2.1 Return of Securitization Proceeds

(1) If an LSE is required under PURA § 39.664 or the Debt Obligation Order in Docket No. 52322 to return securitization proceeds, then the LSE must remit the proceeds to its Qualified Scheduling Entity (QSE), and the QSE shall remit those funds to ERCOT within two Business Days of the QSE receiving the funds from the LSE. The funds must be paid by the QSE to the account designated for payment of Securitization Uplift Charge Invoices.

27.3 Securitization Uplift Charge

(1) ERCOT shall allocate to Qualified Scheduling Entities (QSEs) representing obligated Load Serving Entities (LSEs), the Securitization Uplift Charge that is to be collected for the Operating Day. The resulting charge to each QSE for the Operating Day is calculated as follows:

$$\mathbf{LASUCAMT}_{q,\,d} = \mathbf{SUCDA}_{d} * \mathbf{DQSELSELRS}_{q,\,d}$$

Where:

$$\text{DQSELSELRS}_{q,\,d} = \text{DQSELSERTAML}_{q,\,d} / \text{DERCOTQSELSERTAML}_{d}$$

$$\text{DQSELSERTAML}_{q,\,d} = \max(0, \textstyle\sum_{i,l}(\text{LSERTAML}_{l,\,q,\,i}))$$

$$\text{DERCOTQSELSERTAML}_{d} = \textstyle\sum_{q}(\text{DQSELSERTAML}_{q,\,d})$$

$$\text{LSERTAML}_{l,\,q,\,i} = \text{PRELIMLSERTAML}_{l,\,q,\,i} - \text{OPTOUTLSERTAML}_{l,\,q,\,i}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
LASUCAMT $_{q,\,d}$	$	*Load-Allocated Securitization Uplift Charge Amount per QSE* — The charge allocated to QSE *q*, for the QSE's share of the total amount of Securitization Uplift Charges assessed for Operating Day *d*.
SUCDA $_{d}$	$	*Securitization Uplift Charge Daily Amount* — The total amount of Securitization Uplift Charges assessed for Operating Day *d*.

$\text{DQSELSELRS}_{q,\,d}$	none	*Daily QSE Non-Opted-Out LSE Load Ratio Share* — The ratio of Daily QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load to Daily ERCOT QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load, for a QSE *q*, for the Operating Day *d*.
$\text{PRELIMLSERTAML}_{l,\,q,\,i}$	MWh	*Preliminary Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML), including the RTAML of Securitization Uplift Charge Opt-Out Entities that are Customers of Retail Electric Providers (REPs), but excluding the RTAML of Securitization Uplift Charge Opt-Out Entities that are LSEs and excluding Direct Current Tie (DC Tie) exports, for LSE *l* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
$\text{LSERTAML}_{l,\,q,\,i}$	MWh	*Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML), excluding the RTAML for Securitization Uplift Charge Opt-Out Entities and excluding DC Tie exports, for LSE *l* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
$\text{OPTOUTLSERTAML}_{l,\,q,\,i}$	MWh	*Opt-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML) of Securitization Uplift Charge Opt-Out Entities that are transmission-voltage Customers for LSE *l* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
$\text{DQSELSERTAML}_{q,\,d}$	MWh	*Daily QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML), excluding the RTAML for Securitization Uplift Charge Opt-Out Entities and excluding DC Tie exports, for a QSE *q*, for the Operating Day *d*.
$\text{DERCOTQSELSERTAML}_{d}$	MWh	*Daily ERCOT QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The ERCOT total Real-Time Adjusted Metered Load (RTAML), excluding the RTAML for Securitization Uplift Charge Opt-Out Entities and DC Tie exports, for the Operating Day *d*.
q	none	A QSE
l	none	An LSE
d	none	An Operating Day
i	none	A 15-minute Settlement Interval

(2) As needed, but no less often than quarterly, ERCOT will, to ensure the Securitization Uplift Charge is repaid in substantially equal payments over its term, conduct an evaluation to:

(a) Calculate under-collections or over-collections from the preceding evaluation period;

(b) Estimate any anticipated under-collections or over-collections for the current or upcoming evaluation period; and

(c) Calculate the periodic billing requirement for the upcoming evaluation period, taking into account the total amount of prior and anticipated over-collection and under-collection amounts, and calculate the Securitization Uplift Charge Daily Amount for future periodic billing requirements.

(3) If it is determined in the re-estimation process that the Securitization Uplift Charge Daily Amount needs to be revised, ERCOT will issue a Market Notice notifying Market

Participants of the change no later than 15 calendar days before the Operating Day in which the new Securitization Uplift Charge Daily Amount will become effective.

(4) An LSE that is not a Securitization Uplift Charge Opt-Out Entity is responsible for remitting payment to its QSE for the LSE's share of the Securitization Uplift Charge, based on the LSE's Non-Opted-Out LSE Adjusted Metered Load (AML). An LSE may not pass through the Securitization Uplift Charge to any transmission-voltage Customer that is a Securitization Uplift Charge Opt-Out Entity. ERCOT shall post to the ERCOT website a list that consists solely of every Electric Service Identifier (ESI ID) associated with a transmission-voltage Customer that is a Securitization Uplift Charge Opt-Out Entity. This list of ESI IDs will not include the identity of the Customer or its Retail Electric Provider (REP).

27.4 Securitization Uplift Charge Invoices

27.4.1 Securitization Uplift Charge Initial Invoices

(1) ERCOT shall prepare Securitization Uplift Charge Initial Invoices for the Securitization Uplift Charge, as described in Section 27.3, Securitization Uplift Charge, using Initial Settlement data. ERCOT shall issue Securitization Uplift Charge Initial Invoices for an Operating Day on the same Business Day that Real-Time Market (RTM) Initial Statements are posted to the Market Information System (MIS) Certified Area for the same Operating Day. ERCOT will post the dates that it will issue the Securitization Uplift Charge Initial Invoices under Section 9.1.2, Settlement Calendar. Unless expressly stated otherwise, the publication of Securitization Uplift Charge Initial Invoices can occur as late as 2400 on the scheduled publication date. The Invoice Recipient to whom the Securitization Uplift Charge Initial Invoice is addressed is a net payor.

(2) Each Invoice Recipient shall pay any net debit shown on the Securitization Uplift Charge Initial Invoice on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit.

(3) ERCOT shall post Securitization Uplift Charge Initial Invoices on the MIS Certified Area. The Invoice Recipient is responsible for accessing the Securitization Uplift Charge Initial Invoice on the MIS Certified Area once posted by ERCOT, as described in Section 9.1.3, Settlement Statement and Invoice Access.

(4) The Securitization Uplift Charge Initial Invoice must comply with Settlement payment conventions, as set forth in Section 9.1.5, Settlement Payment Convention.

(5) Securitization Uplift Charge Initial Invoice items must be sorted by Operating Day. Securitization Uplift Charge Initial Invoices must contain the following information:

  (a) The Invoice Recipient's name;

  (b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Run Date – the date on which the Invoice was created and published;

(d) Payment Date and Time – the date and time that Invoice amounts are to be paid;

(e) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes;

(f) Net Amount Owed – the aggregate summary of all charges owed by the Invoice Recipient;

(g) Time Periods – the time period covered for each line item, including Operating Day, Settlement Type (Initial) and Settlement Version Number;

(h) Remittance Information Details – details including the account number, bank name and electronic transfer instructions of the ERCOT Securitization Uplift Charge account to which any amounts owed by the Invoice Recipient are to be paid; and

(i) Overdue Terms – the terms that would be applied if payments were received late.

(6) All disputes for Securitization Uplift Charge Initial Invoices shall follow the process described in Section 9.14, Settlement and Billing Dispute Process.

27.4.2 Securitization Uplift Charge Reallocation Invoices

(1) ERCOT shall prepare Securitization Uplift Charge Reallocation Invoices on a net basis for Securitization Uplift Charges, as described in Section 27.3, Securitization Uplift Charge, based on RTM Final Settlement, True-Up Settlement, and Resettlement data. ERCOT shall issue Securitization Uplift Charge Reallocation Invoices for an Operating Day on the same Business Day that the Statements for RTM Final Settlements, True-Up Settlements and Resettlements are posted to the MIS Certified Area for the same Operating Day. ERCOT will post the dates that it will issue the Securitization Uplift Charge Reallocation Invoices under Section 9.1.2, Settlement Calendar. Unless expressly stated otherwise, the publication of Securitization Uplift Charge Reallocation Invoices can occur as late as 2400 on the scheduled publication date. The Invoice Recipient to whom the Securitization Uplift Charge Reallocation Invoice is addressed is either a net payee or net payor.

(2) A Securitization Uplift Charge Reallocation Invoice will reflect differences to financial records generated on the previous Settlement for a given Operating Day.

(3) Each Invoice Recipient shall pay any net debit and be entitled to receive any net credit shown on the Securitization Uplift Charge Reallocation Invoice on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit or credit.

(4) ERCOT shall post Securitization Uplift Charge Reallocation Invoices on the MIS Certified Area. The Invoice Recipient is responsible for accessing the Securitization Uplift Charge Reallocation Invoice on the MIS Certified Area once posted by ERCOT, as described in Section 9.1.3, Settlement Statement and Invoice Access.

(5) The Securitization Uplift Charge Reallocation Invoice must comply with Settlement payment conventions, as set forth in Section 9.1.5, Settlement Payment Convention.

(6) Securitization Uplift Charge Reallocation Invoice items must be grouped by RTM Final, RTM True-Up and RTM Resettlement categories and must be sorted by Operating Day within each category. Securitization Uplift Charge Reallocation Invoices must contain the following information:

(a) The Invoice Recipient’s name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Run Date – the date on which the Invoice was created and published;

(d) Payment Date and Time – the date and time that Invoice amounts are to be paid or received;

(e) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes;

(f) Net Amount Owed/Due – the aggregate summary of all charges owed by or due to the Invoice Recipient;

(g) Time Periods – the time period covered for each line item, including Operating Day, Settlement Type (Final, True-Up or Resettlement) and Settlement Version Number;

(h) Remittance Information Details – details including the account number, bank name and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient’s account from which ERCOT may draw payments due; and

(i) Overdue Terms – the terms that would be applied if payments were received late.

(7) All disputes for Securitization Uplift Charge Reallocation Invoices shall follow the process described in Section 9.14, Settlement and Billing Dispute Process.

27.4.3 Payment Process for Securitization Uplift Charge Initial Invoices

(1) Payments for Securitization Uplift Charge Initial Invoices are due on a Business Day and Bank Business Day basis as detailed below.

27.4.3.1 Invoice Recipient Payment to ERCOT for Securitization Uplift Charge Initial Invoices

(1) The payment due date and time for the Securitization Uplift Charge Initial Invoice, with funds owed by an Invoice Recipient, is 1700 on the second Bank Business Day after the Securitization Uplift Charge Initial Invoice date, unless the second Bank Business Day is not a Business Day. If the second Bank Business Day is not a Business Day, the payment is due by 1700 on the next Bank Business Day after the second Bank Business Day that is also a Business Day.

(2) All Securitization Uplift Charge Initial Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars (USDs) by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal) on or before the payment due date. EFTs must be with U.S. banks only.

(3) Securitization Uplift Charge Initial Invoices are distinct from other Invoices issued by ERCOT and must be paid by an EFT that is separate from any other Invoice. An Invoice Recipient may not net amounts owing on a Securitization Uplift Charge Initial Invoice with any other funds due to or from ERCOT.

(4) Payments for Securitization Uplift Charge Initial Invoices must be made to the account listed on the Invoice. If payment is not made to the correct account, the payment will be rejected. Failure to remit funds to the correct account may result in a Late Payment and Payment Breach. The payment remarks must include the Invoice number.

27.4.4 Insufficient Payments by Invoice Recipients for Securitization Uplift Charge Initial Invoices

(1) If at least one Invoice Recipient owing funds does not pay its Securitization Uplift Charge Initial Invoice in full (short-pay) by the payment due date and time set forth in Section 27.4.1, Securitization Uplift Charge Initial Invoices, ERCOT shall follow the procedure set forth below:

(a) ERCOT shall draw on any available Securitization Uplift Charge escrow deposit of the short-paying Securitization Uplift Charge Initial Invoice Recipient.

(b) If available Securitization Uplift Charge escrow deposits are insufficient to cover the short-pay amount, ERCOT may utilize Financial Security held with respect to other ERCOT market activities as determined under Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure. ERCOT may not utilize Securitization Default Charge escrow deposits to cover short-pays of Securitization Uplift Charge Initial Invoices.

(c) In the event that an Invoice Recipient short-pays:

(i) Both a miscellaneous Invoice for Securitization Default Charges and a Securitization Uplift Charge Initial Invoice; or

(ii) One or both of the above securitization Invoices as well as any other ERCOT Invoice,

and it is necessary to utilize Financial Security held with respect to other ERCOT market activities, funds drawn from Financial Security will be allocated first to cover short-pays of Invoices for non-securitization activity. Any remaining Financial Security will be allocated pro rata on the basis of unpaid Invoice amounts to Securitization Uplift Charge Initial Invoices and miscellaneous Invoices for Securitization Default Charges.

(d) Regardless of whether ERCOT's draw on an available Securitization Uplift Charge escrow deposits or other Financial Security under paragraphs (a) through (c) above is sufficient to cover the amount owed by a Market Participant for an Initial Invoice for Securitization Uplift Charges, a Market Participant's failure to pay the Initial Invoice by the payment due date and time will still be deemed a Late Payment and Payment Breach under Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(e) If an amount owed to ERCOT for an Initial Invoice for Securitization Uplift Charges cannot be fully recovered from a short-paying Market Participant by drawing upon available Securitization Uplift Charge escrow deposits or taking other action against the Market Participant to recover the amount owed, the remaining short payment amount will be taken into consideration in ERCOT's next evaluation of the Securitization Uplift Charge Daily Amount performed pursuant to paragraph (2) of Section 27.3, Securitization Uplift Charge, that occurs after the short payment.

(f) Any action taken by ERCOT under this Section does not relieve or otherwise excuse the short-paying Market Participant of its obligation to fully pay all outstanding financial obligations to ERCOT, including its obligation to fully pay all Initial Invoices for Securitization Uplift Charges.

[NPRR1125: Replace paragraph (1) above with the following upon system implementation of NPRR1103:]

(1) If at least one Invoice Recipient owing funds does not pay its Securitization Uplift Charge Initial Invoice in full (short-pay) by the payment due date and time set forth in

Section 27.4.1, Securitization Uplift Charge Initial Invoices, ERCOT shall follow the procedure set forth below:

(a) ERCOT shall draw on any available Securitization Uplift Charge escrow deposit of the short-paying Securitization Uplift Charge Initial Invoice Recipient.

(b) If available Securitization Uplift Charge escrow deposits are insufficient to cover the short-pay amount, ERCOT may utilize Financial Security held with respect to other ERCOT market activities as determined under Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure. ERCOT may not utilize Securitization Default Charge escrow deposits to cover short-pays of Securitization Uplift Charge Initial Invoices.

(c) In the event that an Invoice Recipient short-pays:

(i) Both a Securitization Default Charge Invoice and a Securitization Uplift Charge Initial Invoice; or

(ii) One or both of the above securitization Invoices as well as any other ERCOT Invoice,

and it is necessary to utilize Financial Security held with respect to other ERCOT market activities, funds drawn from Financial Security will be allocated first to cover short-pays of Invoices for non-securitization activity. Any remaining Financial Security will be allocated pro rata on the basis of unpaid Invoice amounts to Securitization Uplift Charge Initial Invoices and Securitization Default Charge Invoices.

(d) Regardless of whether ERCOT's draw on an available Securitization Uplift Charge escrow deposits or other Financial Security under paragraphs (a) through (c) above is sufficient to cover the amount owed by a Market Participant for an Initial Invoice for Securitization Uplift Charges, a Market Participant's failure to pay the Initial Invoice by the payment due date and time will still be deemed a Late Payment and Payment Breach under Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(e) If an amount owed to ERCOT for an Initial Invoice for Securitization Uplift Charges cannot be fully recovered from a short-paying Market Participant by drawing upon available Securitization Uplift Charge escrow deposits or taking other action against the Market Participant to recover the amount owed, the remaining short payment amount will be taken into consideration in ERCOT's next evaluation of the Securitization Uplift Charge Daily Amount performed pursuant to paragraph (2) of Section 27.3 that occurs after the short payment.

(f) Any action taken by ERCOT under this Section does not relieve or otherwise excuse the short-paying Market Participant of its obligation to fully pay all outstanding financial obligations to ERCOT, including its obligation to fully pay all Initial Invoices for Securitization Uplift Charges.

27.4.5 Payment Process for Securitization Uplift Charge Reallocation Invoices

(1) Payments for Securitization Uplift Charge Reallocation Invoices are due on a Business Day and Bank Business Day basis as detailed below.

27.4.5.1 Invoice Recipient Payment to ERCOT for Securitization Uplift Charge Reallocation Invoices

(1) The payment due date and time for the Securitization Uplift Charge Reallocation Invoice, with funds owed by an Invoice Recipient, is 1700 on the second Bank Business Day after the Securitization Uplift Charge Reallocation Invoice date, unless the second Bank Business Day is not a Business Day. If the second Bank Business Day is not a Business Day, the payment is due by 1700 on the next Bank Business Day after the second Bank Business Day that is also a Business Day.

(2) All Securitization Uplift Charge Reallocation Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in USDs by EFT in immediately available or good funds (i.e., not subject to reversal) on or before the payment due date. EFTs must be with U.S. banks only.

(3) The Securitization Uplift Charge Reallocation Invoices are distinct from other Invoices issued by ERCOT. An Invoice Recipient may not net amounts owing on a Securitization Uplift Charge Reallocation Invoice with any other funds due to or from ERCOT.

(4) Payments for Securitization Uplift Charge Reallocation Invoices must be made to the account listed on the Invoice. The payment remarks must include the Invoice number. If payment is not made to the correct account, the payment will be rejected. Failure to remit funds to the correct account may result in a Late Payment and Payment Breach.

27.4.5.2 ERCOT Payment to Invoice Recipients for Securitization Uplift Charge Reallocation Invoices

(1) Subject to the availability of funds as discussed in paragraph (2) below, ERCOT must pay Securitization Uplift Charge Reallocation Invoices with funds owed to an Invoice Recipient by 1700 on the next Bank Business Day after payments are due for that Securitization Uplift Charge Reallocation Invoice under Section 27.4.5, Payment Process for Securitization Uplift Charge Reallocation Invoices, subject to ERCOT's right to withhold payments for any reason set forth in these Protocols or as a matter of law, unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit to each Invoice Recipient for same day value the amounts determined by ERCOT to be available for payment to that Invoice Recipient under Section 27.4.6, Insufficient Payments by Invoice Recipients for Securitization Uplift Charge Reallocation Invoices.

27.4.6 Insufficient Payments by Invoice Recipients for Securitization Uplift Charge Reallocation Invoices

(1) If at least one Invoice Recipient owing funds does not pay its Securitization Uplift Charge Reallocation Invoice in full (short-pay), ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient before any payments owed by ERCOT for that Securitization Uplift Charge Reallocation Invoice are due to be paid to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available Financial Security, other than Securitization Default Charge escrow deposits or Securitization Uplift Charge escrow deposits, pledged to ERCOT by the short-paying Invoice Recipient.

(c) Regardless of whether ERCOT's draw on available Financial Security under paragraph (b) above is sufficient to cover the amount owed by a Market Participant for a Securitization Uplift Charges, a Market Participant's failure to pay the Invoice by the payment due date and time will still be deemed a Payment Breach under Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(d) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT for a Securitization Uplift Charge Reallocation Invoice to a short-paying Invoice Recipient, and ERCOT shall apply the amount offset or recouped to cover payment shortfalls by that Invoice Recipient for Invoices other than Securitization Uplift Charge Initial Invoices and Securitization Default Charge Invoices.

(e) If, after taking the actions set forth in the paragraphs above, and subject to paragraph (f) below, ERCOT still does not have sufficient funds to pay all amounts that it owes to Securitization Uplift Charge Reallocation Invoice Recipients in full, ERCOT shall reduce payments to all Securitization Uplift Charge Reallocation Invoice Recipients owed monies from ERCOT. The reductions shall be based on a pro rata basis of monies owed to each Securitization Uplift Charge Reallocation Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT as to Securitization Uplift Charge Reallocation Invoices. ERCOT shall provide to all Market Participants payment details on all short payments and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the Securitization Uplift Charge Reallocation Invoice.

(f) For a short-paying Market Participant whose Standard Form Market Participant Agreement has been terminated, if, after taking the actions set forth in the paragraphs (a) through (d) above, ERCOT still does not have sufficient funds to pay amounts owed to Securitization Uplift Charge Reallocation Invoice Recipients in full, ERCOT will draw on any Securitization Uplift Charge escrow deposit amounts remaining after all Securitization Uplift Charge Initial Invoices for the short-paying Market Participant have been paid in full, in order to recover remaining unpaid Securitization Uplift Charge Reallocation Invoice amounts.

27.4.7 Enforcing the Financial Security of a Short-Paying Reallocation Invoice Recipient

(1) ERCOT shall make reasonable efforts to enforce the Financial Security of the short-paying Securitization Uplift Charge Reallocation Invoice Recipient (pursuant to Section 16.11.6, Payment Breach and Late Payments by Market Participants) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its Financial Security as required under Section 27.5.2, ERCOT Securitization Uplift Charge Initial Invoice Credit Requirements for Counter-Parties.

27.5 Securitization Uplift Charge Initial Invoice Escrow Deposit Requirements

27.5.1 Securitization Uplift Charge Initial Invoice Escrow Deposits

(1) The term “Securitization Uplift Charge escrow deposit” means the amount required to be deposited with ERCOT in the form of cash or an unconditional, irrevocable letter of credit to be held in escrow for a Market Participant’s obligation to pay Securitization Uplift Charge Initial Invoices.

(2) Although ERCOT is the servicer for the assessment and collection of Securitization Uplift Charges, by providing escrow deposits pursuant to this Section each Counter-Party grants the Texas Electric Market Stabilization Funding N LLC (TEMSFN) a secured interest in Securitization Uplift Charge escrow deposits to secure its obligation to pay the same.

(3) The secured interest of TEMSFN is perfected upon a Counter-Party’s deposit of cash or a letter of credit pursuant to this Section.

27.5.2 ERCOT Securitization Uplift Charge Initial Invoice Credit Requirements for Counter-Parties

(1) A Counter-Party must, at all times, maintain its Securitization Uplift Charge escrow deposit at or above the amount of its Load-Allocated Securitization Uplift Charge Credit Exposure (LASUCCE), as determined pursuant to Section 27.5.4, Determination of Securitization Uplift Charge Credit Exposure for a Counter-Party. Each Counter-Party shall maintain any required Securitization Uplift Charge escrow deposit in a form acceptable to ERCOT in its sole discretion pursuant to Section 27.5.3, Means of Satisfying Securitization Uplift Charge Initial Invoice Credit Requirements, below.

(2) If at any time the Counter-Party does not meet ERCOT's LASUCCE requirements, then the Counter-Party will be considered to be in Payment Breach and ERCOT may suspend the Counter-Party's rights and/or take other action authorized under these Protocols until the Counter-Party meets the LASUCCE requirements.

(3) ERCOT's failure to suspend a Counter-Party's rights on any particular occasion does not prevent ERCOT from suspending those rights on any subsequent occasion, including a Congestion Revenue Right (CRR) Account Holder's ability to bid on future CRRs or a Qualified Scheduling Entity's (QSE's) ability to bid in the Day-Ahead Market (DAM).

27.5.3 Means of Satisfying Securitization Uplift Charge Initial Invoice Credit Requirements

(1) If a Counter-Party is required to provide a Securitization Uplift Charge escrow deposit, then it may do so through one or both of the following means:

(a) The Counter-Party may give an unconditional, irrevocable letter of credit naming TEMSFN as the beneficiary. ERCOT or the TEMSFN may reject the letter of credit if the issuer is unacceptable to ERCOT or the TEMSFN or if the conditions under which ERCOT or TEMSFN may draw against the letter of credit are unacceptable to ERCOT or TEMSFN.

(b) All letters of credit must be drawn on a U.S. domestic bank or a domestic office of a foreign bank, and must meet the requirements in Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

(c) Letters of credit held as Securitization Uplift Charge escrow deposits are subject to letter of credit issuer limits as specified in paragraph (1) of Section 16.11.3.

(d) The Counter-Party may deposit cash with TEMSFN through ERCOT with the understanding that ERCOT may draw part or all of the deposited cash to satisfy any overdue payments owed by the Counter-Party to ERCOT for Securitization Uplift Charges. The cash deposits may bear interest payable directly to the Counter-Party, but any such arrangements may not restrict ERCOT's immediate access to the cash.

(i) Interest on cash deposited pursuant to this Section will be calculated based on Counter-Party average cash deposit balances. Interest is not paid on cash deposit balances held by TEMSFN where, in accordance with paragraph (4) of Section 16.11.7, Release of Market Participant's Financial Security Requirement, the Counter-Party's Standard Form Market Participant Agreement has been terminated and ERCOT has determined that no obligations for Securitization Uplift Charges remain owing or will become due and payable.

(ii) Once per year, ERCOT will return interest earned on a Counter-Party's cash deposits pursuant to this Section to the Counter-Party.

(2) Securitization Uplift Charge escrow deposits are held solely for the purpose of collateralizing Securitization Uplift Charge Credit Exposure and shall not be used for any other purpose. They are independent of and in addition to any other Financial Security obligations of the Counter-Party arising under Section 16.11, Financial Security for Counter-Parties, or Section 26, Securitization Default Charges.

(3) Funds provided for Securitization Uplift Charge escrow deposits must be made to the account designated for Securitization Uplift Charge escrow deposits. If a payment is not made to the correct account, ERCOT is not responsible for transferring the funds to the correct escrow deposit account. Failure to remit funds to the correct account by the date and time required will result in a Late Payment and/or Payment Breach.

(4) A Counter-Party with excess cash with respect to Securitization Uplift Charge escrow deposit requirements may request ERCOT to return some or all of the excess cash to the Counter-Party.

(5) Securitization Uplift Charge escrow deposits will not be used to pay periodic Securitization Uplift Charge Initial Invoices unless there is an insufficient payment by the Invoice Recipient, in accordance with Section 27.4.4, Insufficient Payments by Invoice Recipients for Securitization Uplift Charge Initial Invoices.

(6) Cash collateral posted in accordance with Section 16.11.3 may be used to pay Securitization Uplift Charge Reallocation Invoices.

(7) Securitization Uplift Charge escrow deposits in excess of the Securitization Uplift Charge Credit Exposure requirement shall not be used to cover insufficient payments of Settlement Invoices for:

(a) ERCOT market activities under Section 9.19, Partial Payments by Invoice Recipients;

(b) Requests for additional Financial Security made in accordance with paragraph (6) of Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT;

(c) Insufficient payments of Securitization Default Charge Invoices under Section 26.3.1.2, Insufficient Payments by Miscellaneous Invoice Recipients for Securitization Default Charges; or

(d) Requests for Securitization Default Charge Escrow Deposits under Section 26.5, Securitization Default Charge Escrow Deposit Requirements.

27.5.4 Determination of Securitization Uplift Charge Credit Exposure for a Counter-Party

(1) For each Counter-Party, ERCOT shall calculate the Securitization Uplift Charge Credit Exposure for Securitization Uplift Charge Initial Invoices as follows:

$\text{LASUCCE}_{cp} = \sum_{fmu=1}^{nfmu}$(Max (CPMQSELSELRS $_{cp,\ om,\ las}$, CPIEMLSELRS $_{cp}$ up to 40 days after the operating month in which a non-opted-out Counter-Party Load Serving Entity (LSE) commences having Real-Time Adjusted Metered Load (AML)) * MTSUCDA $_{fmu}$)

$$\text{CPMQSELSELRS}_{cp,\ om,\ las} = \sum_{q}(\text{MQSELSELRS}_{q,\ om})$$

$$\text{CPIEMLSELRS}_{cp} = \text{CPIEMLSE}_{cp} / (\text{MERCOTQSELSERTAML}_{om} + \text{CPIEMLSE}_{cp})$$

$$\text{MQSELSELRS}_{q,\ om} = \text{MQSELSERTAML}_{q,\ om} / \text{MERCOTQSELSERTAML}_{om}$$

$$\text{MQSELSERTAML}_{q,\ om} = \sum_{d}(\text{DQSELSERTAML}_{q,\ d})$$

$$\text{MERCOTQSELSERTAML}_{om} = \sum_{q,d}(\text{DQSELSERTAML}_{q,\ d})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LASUCCE $_{cp}$	$	*Load-Allocated Securitization Uplift Charge Credit Exposure* – Estimated forward exposure representing unbilled Securitization Uplift Charge Initial Invoices for Counter-Party *cp* for *nfmu* months.
CPMQSELSELRS $_{cp,\ om,\ las}$	None	*Counter-Party Monthly QSE Non-Opted-Out LSE Load Ratio Share* — MQSELSELRS for all the QSEs represented by the Counter-Party *cp* representing the daily ratios of AML to the total AML, excluding the AML for Securitization Uplift Charge Opt-Out Entities and Direct Current Tie (DC Tie) exports, for a QSE, for all the Operating Days *d* in the operating month *om* for the Settlement Type *las*.
CPIEMLSE $_{cp}$	MWh	*Counter-Party Initial Estimated Monthly Non-Opted-Out LSE Load* — The average estimated load for a full month provided by a non-opted-out Counter-Party *cp* that does not yet have AML.
CPIEMLSELRS $_{cp}$	None	*Counter-Party Initial Estimated Monthly Non-Opted-Out LSE Load Ratio Share* — The Load Ratio Share (LRS) for a Counter-Party *cp* that does not yet have AML, computed using CPIEMLSE.

Variable	Unit	Description
MTSUCDA	$	*Monthly Total of Securitization Uplift Charge Daily Amounts* – The monthly sum of the amounts to be uplifted for all the Operating Days *od* in operating month *om*.
DQSELSERTAML $_{q,\ d}$	MWH	*Daily QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML) excluding the RTAML for Securitization Uplift Charge Opt-Out Entities and DC Tie exports, for a QSE *q*, for the Operating Day *d*.
MQSELSELRS $_{q,\ om}$	none	*Monthly QSE Non-Opted-Out LSE Load Ratio Share* — The ratio of AML to the total AML, excluding the AML for Securitization Uplift Charge Opt-Out Entities and DC Tie exports, for a QSE *q*, for all the Operating Days *d* in the operating month *om.*
MQSELSERTAML $_{q,\ om}$	MWH	*Monthly QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The RTAML excluding the RTAML for Securitization Uplift Charge Opt-Out Entities and DC Tie exports, for a QSE *q*, for all the Operating Days *d* in the operating month *om.*
MERCOTQSELSERTAML $_{om}$	MWH	*Monthly ERCOT QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The ERCOT total RTAML excluding the RTAML for Securitization Uplift Charge Opt-Out Entities and DC Tie exports, for all the Operating Days *d* in the operating month *om.*
cp	none	A registered Counter-Party.
om	none	*Operating Month* – The most recent month for which all the daily ratios of AML to the total AML, excluding the AML for Securitization Uplift Charge Opt-Out Entities and DC Tie exports, for a QSE are available for all days of the month.
fmu	none	*Forward Month* – A month from Securitization Uplift Charge forward months.
nfmu	none	*Number of forward months* – Total number of forward months Monthly Securitization Uplift Charge is extrapolated.
d	none	An Operating Day.

The above parameters are defined as follows:

Parameter	Unit	Current Value
nfmu	Months	2
las	Settlement Type	Load-Allocated Initial Settlements

27.5.5 Monitoring of a Counter-Party's Securitization Uplift Charge Credit Exposure by ERCOT

(1) Pursuant to Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT, ERCOT shall monitor the credit exposure of each Counter-Party, including Securitization Uplift Charge Credit Exposure.

(2) A Counter-Party is responsible at all times for maintaining Securitization Uplift Charge escrow deposits in an amount equal to or greater than that Counter-Party's Securitization Uplift Charge Credit Exposure.

(3) ERCOT shall promptly notify each Counter-Party of the need to increase its Securitization Uplift Charge escrow deposit and allow the Counter-Party time, as provided in paragraph (5) below, to provide additional Securitization Uplift Charge escrow deposits to maintain compliance with this Section.

(4) ERCOT may suspend a Counter-Party when that Counter-Party's LASUCCE, as defined in Section 27.5.4, Determination of Securitization Uplift Charge Credit Exposure for a Counter-Party, equals or exceeds 100% of its Securitization Uplift Charge escrow deposit. Any failure by ERCOT to send a Notice as set forth in this Section does not relieve the Counter-Party from the obligation to maintain appropriate Securitization Uplift Charge escrow deposits in amounts equal to or greater than that Counter-Party's LASUCFME.

(5) To the extent that a Counter-Party fails to maintain Securitization Uplift Charge escrow deposits in amounts equal to or greater than its LASUCCE, as defined in Section 27.5.4:

(a) ERCOT shall promptly notify the Counter-Party of the amount by which its Securitization Uplift Charge escrow deposit must be increased and allow it:

(i) Until 1500 on the second Bank Business Day from the date on which ERCOT delivered the Notice to increase its Securitization Uplift Charge escrow deposit if ERCOT delivered its Notice before 1500; or

(ii) Until 1700 on the second Bank Business Day from the date on which ERCOT delivered Notification to increase its Securitization Uplift Charge escrow deposit if ERCOT delivered its Notice after 1500 but prior to 1700.

(b) If the Counter-Party does not increase its Securitization Uplift Charge escrow deposit to the required amount by the specified time, ERCOT may utilize Financial Security held with respect to other ERCOT market activities as determined under Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure, up to the amount of the Securitization Uplift Charge escrow deposit shortfall.

(c) In the event that a Counter-Party is required to increase both its Securitization Default Charge escrow deposit and its Securitzation Uplift Charge escrow deposit, and ERCOT utilizes the Counter-Party's Financial Security, available Financial Security funds will be allocated on a pro rata basis to Securitization Uplift Charge and Securitization Default Charge escrow deposit requirements.

(d) ERCOT shall notify the QSE's Authorized Representative(s) and Credit Contact if it has not received the required security by 1530 on the Bank Business Day on which the security was due; however, failure to notify the Counter-Party's representatives or credit contacts that the required security was not received does not prevent ERCOT from exercising any of its other rights under this Section.

(e) ERCOT is not required to make any payment to that Counter-Party unless and until the Counter-Party increases its Securitization Uplift Charge escrow deposit to an amount equal to or greater than that Counter-Party's LASUCCE. The payments that ERCOT will not make to a Counter-Party include Invoice receipts, CRR revenues, CRR credits, reimbursements for short payments, and any other reimbursements or credits under any other agreement between the Market Participant and ERCOT. ERCOT may retain all such amounts until the Counter-Party has fully discharged all payment obligations owed to ERCOT under the Counter-Party Agreement, other agreements, and these Protocols.

(6) If a Counter-Party increases its Securitization Uplift Charge escrow deposit as required by ERCOT by the deadline in paragraph (5)(a) above, then ERCOT shall release any payments held, providing the Counter-Party has no other payment deficiencies with respect to any other activity under these Protocols.

27.5.6 Payment Breach and Late Payments by Market Participants

(1) In the event of a Payment Breach or Late Payment by a Market Participant with respect to Securitization Uplift Charge Initial Invoices, Securitization Uplift Charge Reallocation Invoices, or required Securitization Uplift Charge escrow deposits, all remedies specified in Section 16.11.6, Payment Breach and Late Payments by Market Participants, are applicable.

27.5.7 Release of a Market Participant's Securitization Uplift Charge Escrow Deposit Requirement

(1) Following the termination of a Market Participant's Standard Form Market Participant Agreement, ERCOT shall retain all Securitization Uplift Charge escrow deposits to cover, if necessary, potential future obligations for Securitization Uplift Charge Initial Invoices and Securitization Uplift Charge Reallocation Invoices.

(2) Upon ERCOT's sole determination that all potential Securitization Uplift Charge Initial Invoices and Securitization Uplift Charge Reallocation Invoices have been paid, ERCOT shall return or release any remaining Securitization Uplift Charge escrow deposits to the terminated Market Participant.

ERCOT Fee Schedule

Effective August 1, 2022

The following is a schedule of ERCOT fees currently in effect.

Description	Nodal Protocol Reference	Calculation/Rate/Comment
ERCOT System Administration fee	9.16.1	$0.555 per MWh to fund ERCOT activities subject to Public Utility Commission of Texas (PUCT) oversight. This fee is charged to all Qualified Scheduling Entities (QSEs) based on Load represented.
Private Wide Area Network (WAN) fees	9.16.2	Actual cost of using third party communications network - Initial equipment installation cost not to exceed $25,000, and monthly network management fee not to exceed $1,500.
ERCOT Generation Interconnection fee (Not Refundable)	NA	Application to interconnect generation to the ERCOT System. $5,000 (less than or equal to 150MW) $7,000 (greater than 150MW)
Full Interconnection Study (FIS) Application fee (Not Refundable)	NA	$15 per MW – to support ERCOT system studies and coordination. Applicable MW amount per Planning Guide Section 5, Generator Interconnection or Modification.
Map Sale fees	NA	$20 - $40 per map request (by size)
Qualified Scheduling Entity (QSE) Application fee	9.16.2	$500 per Entity
Competitive Retailer (CR) Application fee	9.16.2	$500 per Entity
Congestion Revenue Right (CRR) Account Holder Application fee	9.16.2	$500 per Entity
Independent Market Information System Registered Entity (IMRE) fee	9.16.2	$500 per Entity
Weatherization Inspection fees	NA	Resource Entities with Generation Resources or Energy Storage Resources (ESRs) and Transmission Service Providers (TSPs) shall pay fees to ERCOT for costs related to weatherization inspections conducted pursuant to 16 Texas Administrative Code (TAC) § 25.55 as provided below. TSPs shall pay an inspection fee of $3,000 for each of their substations or switching stations that are inspected. Each Resource Entity with Generation Resources or ESRs shall pay an

<table>
<tr><td></td><td></td><td>inspection fee calculated as the Quarterly Generation Resource Inspection Costs * (Resource Entity MW Capacity/Aggregate MW Capacity). ERCOT will perform this calculation for each calendar quarter and gather the necessary MW capacity data for that quarter on one of the last 15 Business Days at the end of the quarter. Terms used in this formula are defined as follows:

Quarterly Generation Resource Inspection Costs = the sum of outside services costs, ERCOT internal costs, and overhead costs related to weatherization inspections, less inspection fees that will be invoiced to TSPs for that quarter.

Resource Entity MW Capacity = the total MW capacity associated with a Resource Entity with Generation Resources or ESRs. To calculate these amounts, ERCOT will query the Resource Integration and Ongoing Operations-Resource Services (“RIOO-RS”) for a report that lists the total MW capacity (real power rating) for all generation assets associated with each Resource Entity.

Aggregate MW Capacity = the total of all the Resource Entity MW Capacity amounts. To calculate this amount, ERCOT will query the RIOO-RS for a report that lists the total MW capacity (real power rating) for all Generation Resources and ESRs associated with all Resource Entities.

ERCOT will issue Invoices in the first month following each calendar quarter to the Resource Entities and TSPs that owe inspection fees. Payment of the fee will be due within 30 days of the Invoice date and late payments will incur 18% annual interest. Entities that fail to pay their Invoice on time will be publicly reported in a filing with the PUCT. Further payment terms and instructions will be included on the Invoice.</td></tr>
<tr><td colspan="3">***[NPRR1107: Delete “Weatherization Inspection fees” above on July 31, 2023.]***</td></tr>
<tr><td>Voluminous Copy fee</td><td>NA</td><td>$0.15 per page in excess of 50 pages</td></tr>
</table>