ERCOT Protocols

September 1, 2009

ERCOT Protocols
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ERCOT Protocols
Section 1: Overview

May 1, 2009

PUBLIC

1 OVERVIEW

1.1 Summary of the ERCOT Protocols Document

The ERCOT Protocols, created through the collaborative efforts of representatives of all segments of Market Participants, shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in these Protocols, as amended from time to time that contain 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 at a given point in time, the version of 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. These Protocols are intended to implement ERCOT's functions as the Independent Organization for the ERCOT Region as certified by the PUCT and as the Entity appointed by the PUCT that is responsible for carrying out the administrative responsibilities related to the Renewable Energy Credit Program as set forth in PUCT Substantive Rule §25.173(g) ("Program Administrator").

The ERCOT Board, TAC and other ERCOT subcommittees authorized by the Board or TAC ("ERCOT's committees") or ERCOT staff may develop procedures, forms and applications for the implementation of and operation under these Protocols. Except, as provided below, if the provisions in any attachment to these Protocols or in any of the above-described procedures, forms and applications are in conflict with the provisions of Protocols Section 1, Overview through Section 21, Process for Protocols Revision, the provisions of Protocols Sections 1 through Section 21 shall prevail to the extent of the inconsistency. If any express provision of any Agreement conflicts with any provision of the Protocols, the Agreement shall prevail to the extent of the conflict. Agreement provisions that deviate from the Protocols shall expressly state that the Agreement provision deviates from the Protocols. Agreement provisions that deviate from the Protocols shall be effective only upon approval by the ERCOT Board on a showing of good cause. Market Participants and ERCOT shall abide by these Protocols.

These Protocols are not intended to govern the direct relationships between or among Market Participants. ERCOT is not responsible for any relationship between or among Market Participants in which ERCOT is not a party.

1.2 Functions of ERCOT

ERCOT is the Independent Organization certified by the PUCT for the ERCOT Region. The major functions of ERCOT, as the Independent Organization are to:

(1) Ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms;

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

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

(4) Ensure that electricity production and delivery are accurately accounted for among the Generation Resources and wholesale buyers and sellers, and TDSPs in the ERCOT Region.

ERCOT also functions as the PUCT-appointed Program Administrator of the Renewable Energy Credits Program.

These Protocols are intended to implement the above-described functions.

In the exercise of any functions related to deployment of energy or Ancillary Services as described in these Protocols, ERCOT acts only as an agent on behalf of the various Market Participants in fulfilling these duties subject to the settlement process in these Protocols. All references in these Protocols to provision, procurement, purchase, deployment, or dispatch of energy or Ancillary Services or any other similar action shall be interpreted to mean that ERCOT is taking such action on behalf of Market Participants as an agent. Nothing in these Protocols shall be construed as causing ERCOT to take title to any energy or Ancillary Services or to cause TDSPs or Resources to transfer any control of their Facilities to ERCOT. In the exercise of its sole discretion under these Protocols, ERCOT shall act in a reasonable, nondiscriminatory manner.

1.3 Confidentiality

1.3.1 Restrictions on Protected Information

This Section 1.3 shall apply to Protected Information disclosed by a Market Participant to ERCOT or by ERCOT to a Market Participant. ERCOT or any Market Participant (“Receiving Party”) may not Disclose Protected Information received from the other (“Disclosing Party”) to any person, corporation, or any other Entity except as specifically permitted in this Section and in these Protocols. Receiving Party may not use Protected Information except as necessary or appropriate in carrying out responsibilities under these Protocols. To “Disclose” means to, directly or indirectly, disclose, reveal, distribute, report, publish, or transfer Protected Information to any party other than to the Disclosing Party which provided the Protected Information.

1.3.1.1 Items Considered Protected Information

“Protected Information” is information containing or revealing:

(1) Schedule Control Error (SCE), as calculated by ERCOT, identified to a specific Qualified Scheduling Entity (QSE), with the exception of Real Time SCE data that may be

viewable on-site at ERCOT Facilities. The Protected Information status of this information shall expire seven (7) days after the applicable Operating Day.

(2) Bids or pricing information identifiable to a specific QSE. The Protected Information status of this information shall expire if and when posted on the Market Information System (MIS) pursuant to Section 12, Market Information System, but no later than one hundred and eighty (180) days after the applicable Operating Day.

(3) Status of Resources including but not limited to Outages or limitations or scheduled or metered Resource data. The Protected Information status of this information shall expire if and when posted on the MIS pursuant to Section 12, but no later than one hundred and eighty (180) days after the applicable Operating Day.

(4) Resource Plans. The Protected Information status of this information shall expire if and when posted on the MIS pursuant to Section 12, but no later than one hundred and eighty (180) days after the applicable Operating Day.

(5) Energy and Ancillary Service (AS) schedules identifiable to a specific QSE. The Protected Information status of this information shall expire if and when posted on the MIS pursuant to Section 12, but no later than one hundred and eighty (180) days after the applicable Operating Day.

(6) ERCOT Dispatch Instructions identifiable to a specific QSE, except for Out of Merit Capacity (OOMC) and Out of Merit Energy (OOME) deployments as provided in paragraphs (10), (11) and (12) of Section 6.5.10, Out of Merit Capacity and Out of Merit Energy Services, and Replacement Reserve Service (RPRS) deployments for Local Congestion as provided in paragraph (11) of Section 6.5.6, Replacement Reserve Service. The Protected Information status of this information shall expire if and when posted on the MIS pursuant to Section 12, but no later than one hundred and eighty (180) days after the applicable Operating Day.

(7) Raw and Adjusted Metered Load (AML) data (Demand and energy) identifiable to a specific QSE. The Protected Information status of this information shall expire if and when posted on the MIS pursuant to Section 12, but no later than one hundred and eighty (180) days after the applicable Operating Day.

(8) Settlement Statements identifiable to a specific QSE. The Protected Information status of this information shall expire if and when posted on the MIS pursuant to Section 12, but no later than one hundred and eighty (180) days after the applicable Operating Day.

(9) Aggregated raw and AML data (Demand and energy), and number of Electric Service Identifiers (ESI IDs) identifiable to a specific Load Serving Entity (LSE). The Protected Information status of this information shall expire if and when posted on the MIS pursuant to Section 12, but no later than three hundred and sixty-five (365) days after the applicable Operating Day.

(10) Information related to generation interconnection requests prior to a request for full interconnection study, to the extent such information is not otherwise publicly available.

(11) Resource specific costs, design and engineering data, with the exception of data provided pursuant to Section 1.3.1.2, Items Not Considered Protected Information.

(12) Transmission Congestion Right (TCR) ownership, credit limits or bidding information identifiable to a specific TCR Account Holder. The Protected Information status of this information shall expire as follows:

(a) The Protected Information status of the identities of initial auction purchasers shall expire at the end of the auction; and

(b) The Protected Information status of all other TCR information identified above in this paragraph (12) shall expire six (6) months after the year in which the TCR was effective.

(13) Renewable Energy Credit (REC) account balances. At the end of the REC settlement period, this information shall cease to be Protected Information three (3) years after the settlement period.

(14) Credit limits identifiable to a specific QSE.

(15) Any information not submitted to or collected by ERCOT pursuant to requirements of the Protocols or Operating Guides that is designated as Protected Information in writing by Disclosing Party at the time the information is provided to Receiving Party except for information provided to ERCOT in support of a Reliability Must-Run (RMR) application according to Section 6.5.9, Reliability Must-Run Service.

(16) Any Proprietary Customer Information unless the Customer has authorized the release for public disclosure of such information in a manner approved by the Public Utility Commission of Texas (PUCT).

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

(18) QSE and Transmission and/or Distribution Service Provider (TDSP) backup plans collected by ERCOT in compliance with the Protocols or Operating Guides.

(19) Direct Current (DC) Tie information provided to TDSPs pursuant to Section 9.8.2, Direct Current Tie Schedule Information.

(20) Any Texas Standard Electronic Transaction (TX SET) transaction submitted by an LSE to ERCOT or received by an LSE from ERCOT. This paragraph shall not apply to ERCOT in regard to its compliance with PUCT Substantive Rules relating to performance measure reporting, these Protocols, or any Technical Advisory Committee (TAC) approved reporting requirements.

(21) Mothballed Generation Resource updates and supporting documentation submitted pursuant to Section 6.5.9.3, Generation Resource Return to Service Updates.

(22) The unavailability of Switchable Resources to the ERCOT System and supporting documentation submitted pursuant to paragraph (5) of Section 16.5.3, Requirements for Reporting and for Changing the Terms of a Resource Registration, except for reporting the aggregate capacity of Switchable Resources for reserve margin calculations.

(23) Information provided by Entities under Section 10.3.2.4, Reporting of Net Generation Capacity.

(24) Alternative fuel reserve capability and firm gas availability information submitted pursuant to Sections 5.6.3, Operating Condition Notice, 5.6.4, Advisory, and 5.6.5, Watch; and as defined by the Operating Guides.

(25) Non-public financial information provided by QSEs to ERCOT pursuant to meeting their credit qualification requirements as well as the QSE's form of credit support.

(26) 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 Standards (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.

1.3.1.2 Items Not Considered Protected Information

Notwithstanding the foregoing, the following items shall not be considered Protected Information, even if so designated:

(1) Data comprising Load flow cases. Such data may include estimated peak and off-peak Demand of any Load;

(2) Existence and tuning of power system stabilizers of each interconnected Generation Resource;

(3) RMR Agreements, applicable portions of studies, reports and data, excluding information that is otherwise considered as Protected Information according to Section 1.3.1.1, Items Considered Protected Information, used in ERCOT's assessment of whether an RMR Unit satisfies ERCOT's criteria for operational necessity to support ERCOT System reliability, and status of RMR Units and RMR Synchronous Condenser Units;

(4) Information provided to ERCOT in support of an "Application for Reliability Must Run (RMR) Status" according to Section 6.5.9, Reliability Must-Run Service;

(5) Black Start Agreement terms;

(6) All OOMC, OOME, and RMR studies performed and used by ERCOT as the basis for their OOMC, OOME, and RMR deployment decisions;

(7) Immediately subsequent to a request from a potential generating Facility for a full interconnection study, the county in which the Facility is located, Facility fuel type(s), Facility nameplate capacity, and anticipated in-service date(s); and

(8) Any other information specifically designated in these Protocols or in PUCT Substantive Rules as information to be posted to all Market Participants or to the public.

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.

1.3.2 Procedures for Protected Information

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

(1) The Protected Information will be Disclosed to Receiving Party's directors, officers, employees, representatives and agents only on a "need to know" basis;

(2) Receiving Party shall make its directors, officers, employees, representatives and agents aware of Receiving Party's obligations under this Section 1.3, Confidentiality;

(3) If reasonably practicable, 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

(4) Before Disclosing Protected Information to a representative or agent of Receiving Party, Receiving Party shall require a nondisclosure agreement with such representative or agent. Such nondisclosure agreement shall contain confidentiality provisions substantially similar to the terms of this Section 1.3, Confidentiality.

1.3.3 Expiration of Confidentiality

(1) If P.U.C. 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) Upon the expiration of the Protected Information status, any market data specified in Section 1.3.1.1 which does not have specific posting requirements, shall be available in accordance with Section 12, Market Information System.

1.3.4 Protecting Disclosures to the PUCT and Other Governmental Authorities

Any Disclosure that ERCOT is required to make to the PUCT shall be made in accordance with applicable PUCT rules. For any filings of Protected Information to the PUCT outside the scope of PUCT Substantive Rule 25.362(e), as amended or superceded, ERCOT shall file such Protected Information as confidential pursuant to PUCT Procedural Rule 22.71(d), as amended or superceded. Before making a Disclosure pursuant to an order of a Governmental Authority, other than the PUCT, ERCOT shall seek a protective order from such Governmental Authority to protect the confidentiality of Protected Information.

1.3.5 Notice Before Permitted Disclosure

Before making any Disclosure permitted under Section 1.3.4, Protecting Disclosures to the PUCT and Other Governmental Authorities, above and Section 1.3.6, Exceptions, below, other than ERCOT Disclosures made to the PUCT, Receiving Party shall promptly notify Disclosing Party in writing and shall assert confidentiality and cooperate with the Disclosing Party in seeking to protect the Protected Information from Disclosure by confidentiality agreement, protective order, aggregation of information, or other reasonable measures. ERCOT shall not be required to provide notice to the Disclosing Party of Disclosures made pursuant to Section 1.3.6, Exceptions, item (2) below.

1.3.6 Exceptions

Receiving Party may, without violating this Section 1.3, Confidentiality, disclose certain Protected Information:

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

(2) If ERCOT is the Receiving Party and Disclosure to the PUCT of the Protected Information is required from ERCOT pursuant to applicable Protocol, law, regulation or order; or

(3) If Disclosing Party that supplied the Protected Information to the Receiving Party has given its prior written consent to the Disclosure, which consent may be given or withheld in Disclosing Party's sole discretion; or

(4) If the Protected Information, before it is furnished to Receiving Party, is in the public domain; or

(5) If the Protected Information, after it is furnished to Receiving Party, enters the public domain other than as a result of a breach by Receiving Party of its obligations under this Section 1.3, Confidentiality; or

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

(7) To a TDSP engaged in transmission or distribution system planning and operating activities, provided that the TDSP has executed a confidentiality agreement with requirements substantially similar to those in Section 1.3, Confidentiality; or

(8) To a vendor or prospective vendor of goods and services to ERCOT so long as such vendor or prospective vendor: (i) is not a Market Participant and (ii) agrees to abide by the terms of Section 1.3, Confidentiality, regarding management of Protected Information; or

(9) To NERC if required for compliance with any applicable NERC requirement; or

(10) To ERCOT and its consultants, and members of task forces and working groups of ERCOT engaged in performing analysis of abnormal system conditions, disturbances, unusual events, and abnormal system performance, provided that Ancillary Service Bid prices or other competitively sensitive price or cost information shall not be disclosed, and further provided that the members of task forces and working groups execute a confidentiality agreement with requirements substantially similar to those in Section 1.3, Confidentiality. Data to be disclosed under this exception shall be limited to clearly defined periods surrounding the relevant conditions, events, or performance under review and will be limited in scope to information pertinent to the condition or events under review and may include the following:

(a) QSE base schedules;

(b) QSE AS awards and deployments, in aggregate and by type of Resource;

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

(d) Individual Resource information including, real power output, reactive output, and maximum/minimum generating capability;

(e) Resource control mode and protective device settings and status;

(f) QSE SCE and its components, including governor response, bias, and droop setting;

(g) Load Imbalance;

(h) Data from Resource Plans; and

(i) Resource Outage schedule information.

Such information shall not be disclosed to other Market Participants prior to ten (10) days following the date(s) under review.

1.3.7 Specific Performance

It will be impossible or very difficult to measure in terms of money the damages that would accrue due to any breach by Receiving Party of this Section 1.3, Confidentiality, or any failure to perform any obligation contained in this Section 1.3, Confidentiality, and, for that reason, among others, a Disclosing Party affected by a Disclosure or threatened Disclosure is entitled to specific performance of this Section 1.3, Confidentiality. In the event that a Disclosing Party institutes any proceeding to enforce any part of this Section 1.3, Confidentiality, 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 Declassification

After providing reasonable notice and opportunity for hearing to ERCOT and a Disclosing Party, to the extent that the Disclosing Party is known by the PUCT, the PUCT may reclassify Protected Information as non-confidential in accordance with applicable PUCT rules.

1.3.9 Expansion of Protected Information Status

A Market Participant may petition the PUCT to include specific information not listed in 1.3.1.1, Items Considered Protected Information, within the definition of Protected Information for good cause. In addition, a Market Participant may petition the PUCT to expand the time period for maintaining Protected Information status of specific information, or prohibit disclosure altogether, for good cause. After reasonable notice and opportunity for hearing, the PUCT may grant or deny such petition.

1.4 Operational Audit

1.4.1 Materials Subject to Audit

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 this Section 1.4, Operational Audit.

1.4.2 *ERCOT Finance and Audit Committee*

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. The ERCOT F&A Committee shall appoint an external independent certified public accounting firm or firms ("Appointed Firm") to conduct certain audits. The F&A Committee may also direct the ERCOT Internal Audit Department to conduct certain audits. For audits to be performed by an Appointed Firm, the F&A Committee shall make recommendations to the ERCOT Board in relation to the approval, initiation and scheduling of such 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 review ERCOT management's compliance with its market operations policies and procedures. The scope of the audit(s) shall include examination of the processing of ERCOT's receipts and disbursements as the agent on behalf of Market Participants in compliance with these Protocols and any audit required by the PUCT. ERCOT may incorporate the scope of this audit into its annual Statement on Auditing Standards (SAS) No. 70 ("SAS 70"), Type II report.

(2) The ERCOT Internal Audit Department will conduct an annual audit of the following:

(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 PUCT.

1.4.3.2 Material Issues

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

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

(2) 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.

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

Unless a longer time frame is reasonably necessary (e.g., for the market settlements audit [SAS 70, Type II Audit], which is performed over a significant period of time), each audit report will be prepared and finalized no later than four (4) months after the initiation of the audit. Results of all audits performed pursuant to this Section shall be reported to the 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 F&A Committee. The results of the audits required by this Section and 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

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 (4) years and not be required for more than seven (7) 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

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 to 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

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. A schedule of ERCOT fees and charges will be posted on the Market Information System.

1.6 Rules of Construction

(1) Capitalized terms and acronyms used in the Protocols shall 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, Definitions and Acronyms, 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, Definitions and Acronyms, controls in all other Sections of the Protocols; and

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

(a) The singular shall include 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 shall mean a Section, or Attachment, or Exhibit of these Protocols;

(k) References to any statutes or regulations, tariffs or these Protocols shall be 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 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.

1.7 Effective Date

These Protocols shall be fully effective on January 1, 2002; provided, however, that individual sections of these Protocols, or portions thereof, shall be effective on earlier or later dates as necessary to support the Market Implementation Plan and the Protocols Implementation Plan as each is approved by the ERCOT Board and in accordance with applicable laws and regulations. The Sections of these Protocols related to the implementation of the wholesale market under a single Control Area shall be effective on July 31, 2001, unless further delayed by ERCOT. All Market Participants (including TDSPs, Resources, Load Serving Entities, QSEs, and NOIEs) intending to participate in any aspect of the wholesale or pilot retail market starting on July 31, 2001 must register with ERCOT in time to perform under these Protocols as of July 31, 2001, unless further delayed by ERCOT.

ERCOT Protocols

Section 2: Definitions and Acronyms

September 1, 2009

2 DEFINITIONS AND ACRONYMS

2.1 Definitions

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
Retail Load usage data that has been adjusted for UFE and transmission and/or distribution losses.

Adjustment Period
The Adjustment Period for any given Operating Hour is the time period following the close of the Day-Ahead market and extending up to each Operating Period.

Advanced Meter
Any new or appropriately retrofitted meter that functions as part of an Advanced Metering System and 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.

Advisory
The second of four possible levels of communication issued by ERCOT in anticipation of a possible emergency condition detailed in Section 5.6.

Affiliate
(a) An Entity who directly or indirectly owns or holds at least five percent of the voting securities of another Entity; or

(b) An Entity in a chain of successive ownership of at least five percent of the voting securities of another Entity; or

(c) An Entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by another Entity; or

(d) An Entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by an Entity who directly or indirectly owns or controls at least five percent of the voting securities of another Entity or an Entity in a chain of successive ownership of at least five percent of the voting securities of another Entity; or

(e) A person who is an officer or director of another entity or of a corporation in a chain of successive ownership of at least five percent of the voting securities of an Entity; or

(f) An Entity that actually exercises substantial influence or control over the policies and actions of another Entity; or

(g) Any other Entity determined by the PUCT to be an Affiliate.

Aggregated Retail Load Data
Adjusted Metered Load that has been aggregated as defined in Section 11.5.1, Aggregate Retail Load Data.

Aggregated Unit
A single plant or facility containing two or more individual generation units that require tandem operation for optimal performance (e.g. a combined cycle plant) which ERCOT has agreed to treat as a single unit for settlement purposes only as set forth in Protocols Section 6.8.2.4, Aggregating Units.

Agreement
Standard form Agreement executed between ERCOT and Market Participants.

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

Ancillary Services
Those services, described in Section 6, necessary to support the transmission of energy from Resources to Loads while maintaining reliable operation of transmission provider's transmission systems in accordance with Good Utility Practice.

Ancillary Service Obligations
***See* Obligations**

Ancillary Services Plan
ERCOT produced plan, as described in Section 6, Ancillary Services, that identifies the types and amount of Ancillary Services necessary for each hour of the next day, or next two (2) days, to operate the ERCOT Transmission Grid reliably in accordance with Operating Guides, and which includes the allocation of types and amounts of the Ancillary Services Obligations for each QSE.

Ancillary Service Supply
***See* Supply**

Annual Transmission Planning Report
A report prepared at least annually by ERCOT, as required by the PUCT rules, regarding the status of the ERCOT System including identification of ERCOT System existing and potential Congestion, which includes identification of current and recommended construction of Transmission Facilities.

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
A device used on Generation Resources to automatically maintain a voltage set point.

Availability Plan
An hourly representation of availability of RMR, Synchronous Condenser and/or Black Start Resources submitted to ERCOT by Entities with RMR, Synchronous Condenser and/or Black Start Resources by 0600 in the Day Ahead Period.

Average Daily Usage
The ratio of the total consumption divided by the number of days the consumption covered. (ADU = Monthly kWh/# of days).

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BES-Capable Off-line Non-Spinning Reserve Service (Off-line BESCNSRS)
A service that is provided through utilization of generation capacity capable of being synchronized and ramped to a specific output level within fifteen (15) minutes that is also capable of providing Balancing Energy Service or Load that is capable of providing Balancing Energy Service, and that is not participating in any other activity, including ERCOT markets, self-generation and other energy transactions. Resources will be allowed to provide this service as determined by ERCOT. Any Resource desiring to provide this service must be approved by ERCOT before such service can be offered.

BES-Capable On-line Non-Spinning Reserve Service (On-line BESCNSRS)
A service that is provided through utilization of On-line generation capacity capable of being ramped to a specific output level within fifteen (15) minutes that is also capable of providing Balancing Energy Service. Resources will be allowed to provide this service as determined by ERCOT. Any Resource desiring to provide this service must be approved by ERCOT before such service can be offered.

Balanced Schedule
An Energy and Ancillary Service schedule submitted to ERCOT by a Qualified Scheduling Entity that consists of projected interval Obligations and projected interval Supply, and that includes Qualified Scheduling Entity Obligations for Transmission and Distribution Losses. A Balanced Schedule must have projected aggregate Supply equal to projected aggregate Obligations, by Settlement Interval.

Balancing Energy
Balancing Energy represents the change in zonal energy output or demand determined by ERCOT to be needed to ensure secure operation of ERCOT Transmission Grid, and supplied by the ERCOT through deployment of bid Resources to meet Load variations not covered by Regulation Service.

Bank Business Day
***See* Business Day**

Bankrupt
The condition of an Entity when such Entity (i) 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, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) 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 (iv) is generally unable to pay its debts as they fall due.

Bid Stack
Bids received for Ancillary Services organized from lowest price to highest price bid for the same service and time interval.

Black Start Service
A contracted Ancillary Service acquired by ERCOT for the benefit of all Loads, provided by Resource capable of starting without support of the ERCOT Transmission Grid.

Black Start Resource
A single Resource capable of providing Black Start Service.

Block Load Transfer
A transfer scheme which isolates a group of loads from the Control Area in which they normally are served and subsequently interconnects them with an adjacent Control Area. Such transfer schemes involve either transferring loads normally in ERCOT to a Non-ERCOT Control Area or transferring loads normally in Non-ERCOT Control Areas to the ERCOT Control Area. Block Load Transfers specifically exclude transfers of load between ERCOT and Non-ERCOT Control Areas that occur behind a retail settlement meter.

Boundary Generation Resources
Those Resources, identified prior to ERCOT's annual TCR auction, on a unit-specific basis, that are related to a combination of CSC and CRE, and whose impacts on the CRE are opposite to those on the related CSC.

Business Day
Monday through Friday, excluding ERCOT observed holidays listed below:

(1) New Year's Day

(2) Memorial Day

(3) Independence Day

(4) Labor Day

(5) Thanksgiving Thursday and Friday

(6) Two (2) days at Christmas, as designated 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 above except in the case of retail transactions processed by a TDSP, CRs shall substitute TDSP holidays for ERCOT holidays when determining the time available to the TDSP to process the transaction. For additional, important information related to Retail Business Days, please refer to the Retail Market Guide.

Business Hours
8:00 A.M. to 5:00 P.M. Central Prevailing Time on Business Days.

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Capital Asset
An asset expected to have a useful life of at least twelve (12) months that is not bought or sold in the normal course of business.

Capital Expenditure
An outlay of money to acquire a Capital Asset or extend the useful life of an existing Capital Asset for at least twelve (12) months.

Central Prevailing Time
Either Central Standard Time or Central daylight time as established by national time standards.

Certificate of Compliance
A certificate issued by ERCOT stating that the Metering Facilities referred to in the certificate satisfy the certification criteria for Metering Facilities contained in these Protocols.

Check Meter
A redundant revenue quality meter, which produces equal or better accuracy than the primary revenue quality meter, connected at the same metering point, which must be certified in accordance with the ERCOT Protocols.

Closely Related Elements (CREs)
Those transmission facilities that have shift factor impacts similar to those associated with a particular Commercially Significant Constraint (CSC), and for which there exists a limited amount of Boundary Generation Resources between it and the particular CSC, so that the zonal deployment of Balancing Energy Service is effective in mitigating Zonal Congestion.

Comision Federal de Electricidad (CFE)
The state-owned federal commission of electricity of Mexico. The government agency in Mexico charged with the responsibility of operating the Mexican national electricity grid (outside Mexico City).

Commercial Model
Transmission model developed by ERCOT that arranges groups of Generation Resource and Load busses into Congestion Zones that have similar impacts on Commercially Significant Constraints.

Commercially Significant Constraint (CSC)
A constraint in the ERCOT Transmission Grid that is found, through the process described in Section 7, to result in Congestion which limits the free flow of energy within the ERCOT market to a commercially significant degree.

Commercially Significant Constraint (CSC) Limit
The maximum power flow across a CSC allowed to maintain reliable operation.

Competitive Retailer (CR)
Municipally Owned Utility or an Electric Cooperative 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 25.5 of the PUCT Substantive rules.

> **Competitive Retailer (CR) of Record**
> The Competitive Retailer assigned to the 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 Premium
A Compliance Premium is awarded by the program administrator in conjunction with a Renewable Energy Credit (REC) that is generated by a renewable energy source that is not powered by wind and meets the criteria of subsection (m) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. For the purpose of the renewable energy portfolio standard requirements, one Compliance Premium is equal to one REC.

Congestion
The situation that exists when requests for power transfers across a Transmission Facility element or set of elements, when netted, exceed the transfer capability of such elements.

Congestion Zone
A grouping of busses that create a similar Shift Factor on CSCs.

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, which continuously regulates, through automatic Resource control, its Resource(s) and interchange schedules to match its system Load, regulates frequency, and meets all applicable Control Area requirements.

Control Area Operator
An individual or set of individuals responsible for monitoring and control operation of the Control Area.

CR of Record
***See* Competitive Retailer**

Current Operating Plan
***See* Ancillary Services Plan**

Current System Conditions
The Real Time status of the ERCOT System, which may affect ERCOT's operational decisions.

Customer
An Entity that purchases electricity for its own 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 Choice Pilot
A project used to allow the PUCT to evaluate the implementation of Customer Choice as provided in PURA 39.104.

Customer Premise
***See* Premise.**

Customer Registration Database
The database maintained by the Registration Agent containing information identifying each Premise, including current and previous Competitive Retailers serving the Premise.

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Data Aggregation
The process of netting, grouping and summing Load consumption data, applying appropriate profiles, Transmission Loss Factors, and Distribution Loss Factors and calculating and allocating UFE to determine each QSE and/or Load Serving Entities responsibility by Settlement Interval by Congestion Zone and by other prescribed aggregation determinants.

Data Aggregation System
The database and communication system that will collect meter data from TDSPs and directly polled meters in ERCOT. The system will perform aggregation functions to the Load data in order to satisfy certain objectives such as providing TDSPs with Load share data to use in billing Competitive Retailers, assigning QSE Load responsibility, and assisting Competitive Retailers and QSEs in their settlement responsibilities. The data will also be compiled along Congestion and weather zones.

Data Archive
An integrated normalized data structure of all the target source systems' transactions. The population of the data archive will be an extraction of data from the transaction systems without transforming the data. The Data Archive will be 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 is generally lightly indexed.

Day Ahead
The twenty-four (24) hour period prior to the beginning of the Operating Day.

Delivery Plan
A plan by ERCOT containing the hours and levels of operation that an RMR Unit, including Synchronous Condenser Unit, is instructed to operate.

Demand
Instantaneous or integrated power consumption

Direct Current Tie, DC Tie
Any non-synchronous transmission interconnections between ERCOT and non-ERCOT electric power systems.

Direct Load Control
Controlling select end-use equipment (e.g. A/C, water heaters) for purposes of reducing or increasing energy consumption during select periods.

Dispatch
The act of issuing Dispatch Instructions.

Dispatch Instruction(s)
Specific command(s) issued by ERCOT to QSEs or TDSPs during the course of operating the ERCOT System.

Distributed Renewable Generation
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 Losses
The difference between the energy delivered to the Distribution System and the energy consumed by Loads connected to the Distribution System.

Distribution Loss Factor
The ratio of the Distribution Service Provider's estimated Distribution Losses to the total amount of energy deemed consumed (IDR plus profiled consumption) on the Distribution Service Provider's system.

Distribution Service Provider
An Entity that owns and maintains a Distribution System for the delivery of energy from the ERCOT Transmission Grid to the Customer.

Distribution System
That portion of an electric delivery system operating at under 60 kilovolts (kV) that provides electric service to Customers or Wholesale Customers.

DUNS Number
A unique nine-digit common company identifier used in electronic commerce transactions.

Dynamic Schedule
A Real Time telemetered signal to ERCOT derived from an actual metered Load that represents an energy Obligation and Resource in a QSE schedule, as further described in Section 4, Scheduling.

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EILS Contract Period
A time frame during which ERCOT may procure EILS in an amount no greater than 1000 MW. Unless otherwise announced by ERCOT at least ninety (90) days prior to the start of an EILS Contract Period, the standing EILS Contract Periods are February through May, June through September, and October through January.

EILS Resource
A Load that is contracted to provide EILS.

EILS Self-Provision
The act by a QSE to meet its Load Ratio Share (LRS) of the total EILS procurement by designating Load to act as an EILS Resource. The EILS Resource self-providing EILS bids its Load at a price of zero (0) dollars.

Electric Cooperative
(a) A corporation organized under Chapter 161, Texas Utilities Code, or a predecessor statute to Chapter 161 and operating under that chapter;

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

(c) A successor to an electronic cooperative created before June 1, 1999, in accordance with 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, as defined in §39.151 of PURA, for the ERCOT Region.

Electric Reliability Organization (ERO)
The organization approved by the FERC to perform the electric reliability organization functions described in the Electricity Modernization Act of 2005 (16 U.S.C. §824 et seq.).

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

Eligible Transmission Service Customer
A Transmission and/or Distribution Service Provider (for all uses of its Transmission System) or any electric utility, municipally owned utility, Electric Cooperative, Power Generation Company, Competitive Retailer, Retail Electric Provider, federal power marketing agency, exempt wholesale generator, qualifying facility, power marketer, or other person whom the Public Utility Commission of Texas has determined to be an Eligible Transmission Service Customer.

Emergency Condition
That operating condition where the safety or reliability of the ERCOT System is compromised or threatened, as determined by ERCOT.

Emergency Interruptible Load Service (EILS)
A special emergency service used during an EEA Level 2B to reduce Load and assist in maintaining or restoring ERCOT System frequency.

Emergency Interruptible Load Service Time Period (EILS Time Period)
Blocks of hours in an EILS Contract Period in which EILS Resources are contractually committed to provide EILS. EILS Time Periods shall be defined by ERCOT in the Request for Proposal specific to an EILS Contract Period.

Emergency Notice
The fourth of four possible levels of communication issued by ERCOT in anticipation of a possible Emergency Condition detailed in Section 5.6.

Emergency Short Supply
The condition wherein ERCOT experiences an insufficient amount of bids in any Ancillary Services market, as described in Section 6.

Energy Emergency Alert (EEA)
An orderly, predetermined procedure for maximizing use of available Resources and, only if necessary, curtailing Demand during electric system emergencies while providing for the maximum possible continuity of service and maintaining the integrity of the ERCOT System.

Energy Obligations
***See* Obligations**

Energy Ratio Share
A QSE’s ratio of Adjusted Metered Load plus Settlement Meter energy output from Uncontrollable Renewable Resources electing to utilize Renewable Production Potential for URC and OOME to total ERCOT Adjusted Metered Load plus Settlement Meter energy output from Uncontrollable Renewable Resources electing to utilize Renewable Production Potential for URC and OOME related to the appropriate interval.

Energy Supply
***See* Supply**

Engineering Studies
Studies performed by ERCOT for the purpose of studying, evaluating, or planning of the ERCOT System.

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

ERCOT Board
The Board of Directors of the Electric Reliability Council of Texas.

ERCOT CEO
ERCOT Chief Executive Officer.

ERCOT Member
Any member of ERCOT that is a member in good standing in accordance with the ERCOT Bylaws.

ERCOT Metered Entity
Any one of the following entities that meets the requirements of Section 10.2.3, ERCOT Polled Settlement Meters:

(1) Any Generation connected directly to the transmission system;

(2) Any Generation equal to or over 10MW;

(3) Any Generation participating in any ancillary service market;

(4) Non-opt-in Cooperatives and Municipality points of delivery over 10MW; or

(5) Direct-Current ties (or interchanges with other control areas outside of ERCOT).

Additionally ERCOT will directly poll any generator or non-opt-in utility metering point at the request of the entity if the entity meets all requirements and certifications associated with EPS metering.

ERCOT Polled Settlement (EPS) Meter
Any meter polled by ERCOT as defined in Section 10 for use in the financial settlement of the Market.

ERCOT Region
The geographic area under the jurisdiction of the PUCT that is served by TDSPs that are not synchronously interconnected with electric utilities outside the state of Texas.

ERCOT Service Fee Schedule
Schedule of fees charged by ERCOT for various services provided to designated Entities, in accordance with these Protocols and/or as approved by the ERCOT Board, and as posted on the MIS.

ERCOT System
The interconnected combination of generation, transmission, and distribution components in the ERCOT Region.

ERCOT System Load
The sum of all HVDC interconnections and Generation Resources metered at the point of its interconnection with the ERCOT System at any given point in time.

ERCOT Transmission Grid
All of those Transmission Facilities which are within the ERCOT Region.

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

Final Day-Ahead Schedule
Those schedules ERCOT deems valid following the close of the Day Ahead period.

Final Statement
***See* Settlement Statement**

Financing Persons
The lenders, security holders, investors, partners, multilateral institutions, and others providing financing or refinancing for the business of 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.

Forced Derate
For a Generation Resource, a failure that requires immediate removal (either through controlled or un-controlled actions) of a portion of the capacity of the Resource from service through automated or manual means. The portion of the Resource removed from service must exceed two-percent (2%) of its prior High Sustainable Limit (HSL) for Generation Resources larger than 500 MW and ten-percent (10%) of its prior HSL for Generation Resources smaller than 500 MW. For Qualified Scheduling Entities (QSEs) representing Wind-powered Generation Resources (WGRs), 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 weather. For QSEs representing WGRs, the percentage calculation will be determined using the generating unit's maximum net power.

Fuel Index Price (FIP)
The FIP is the Midpoint price expressed in $/MMBTU, published in Gas Daily, in the Daily Price Survey, under the heading "East-Houston-Katy, Houston Ship Channel" for the day of OOME deployment. The FIP for Saturdays, Sundays, holidays and other days for which there is no FIP published in Gas Daily, shall be the next published FIP after the day of OOME deployment. In the event that the FIP is not published for more than two (2) days, the previous day published FIP will be used for initial settlement and the next day published FIP will be used for true up of the final settlement statement. In the event that Gas Daily pricing is no longer published, the ERCOT Board of Directors may designate a substitute index.

Fuel Oil Price (FOP)
The Market Participant may use either of the following two fuel oil index prices:

(1) Gulf Coast No. 2

The sum of five cents plus the average of the *Platts Oilgram Price Report* for U.S. Gulf Coast, pipeline No. 2 oil, converted to dollars per million British thermal units ($/MMBtu). The conversion is 0.1385 MMBtu per gallon. The *Platts Oilgram Price Report* indicates which Operating Days the prices are effective. For Saturdays, Sundays, holidays, and other days for which *Platts Oilgram Price Report* does not publish an effective price, the effective price shall be the effective price for the Operating Day following the holiday or day without a published price. 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.

(2) Ultra Low Sulfur (ULS) Diesel #2
The sum of five cents plus the average of the Platts Oilgram Price Report for ULS Diesel #2, converted to dollars per million British thermal units ($/MMBtu). The conversion is 0.1385 MMBtu per gallon. The Platts Oilgram Price Report indicates which Operating Days the prices are effective. For Saturdays, Sundays, holidays, and other days for which Platts Oilgram Price Report does not publish an effective price, the effective price shall be the effective price for the Operating Day following the holiday or day without a published price. In the event, at the time of settlement or caluculation 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.

Force Majeure Event
Any event beyond the reasonable control of, and that occurs without the fault or negligence of, the Entity whose performance is prevented by the occurrence of such event. Examples of such a Force Majeure Event include, but are not limited, to: 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.

Frequency Bias of Portfolio
A positive (+) value, in megawatts per 0.1Hz, to represent response of a QSE's Resources to a deviation in frequency from scheduled frequency.

Fuel Index
An electronically-published index that reflects the price of fuel as determined by a fuel industry organization using available market information.

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Generation Entity
Owner or controller of a Generation Resource used for generating electricity and electrically connected to the ERCOT System.

Generation Resources
Facilities that produce energy and that are owned or operated by a Generation Entity.

Good Utility Practice
Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric 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; provided, however, a Governmental Authority who is also a Market Participant shall 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.

Gross Generation
The generated output power at the terminals of the generator.

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High Operating Limit (HOL)
The maximum net dependable capability of a Resource that may be delivered for a period of up to one hour.

High Sustainable Limit (HSL)
The maximum net capability of a Resource that may be delivered for an indefinite period.

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IDR Data Threshold
The percentage of IDR data by MRE that must be available before ERCOT will calculate a True-Up Settlement as set forth in Protocols Section 9.2.6, True-Up Statement.

IDR Optional Removal Threshold
The kW (kVA) level at which an interval data recorder may be removed as set forth in Section 18.6.7, IDR Optional Removal Threshold.

IDR Mandatory Installation Threshold
The kW (kVA) level at which the installation of interval data recorders are required for settlement purposes as set forth in Protocols Section 18.6.1, Interval Data Recorder Installation and Use in Settlement.

Inadvertent Energy Account
An account maintained by ERCOT to track any differences between the scheduled net interchange, and the actual net interchange at the DC Tie.

Initial Settlement
***See* Settlement Statement**

Inter-QSE Trade
Any Energy and Ancillary Services scheduled to or from other QSEs or ERCOT.

Interconnection Agreement
An agreement that sets forth requirements for physical connection between an Eligible Transmission Service Customer and Transmission and/or Distribution Service Providers.

Interval Data Recorder (IDR)
Metering Device that is capable of recording Load usage in each Settlement Interval in accordance with Section 9, Settlement and Section 10, Metering.

Invoice

> **Settlement Invoice**
> A notice for payment or credit due rendered by ERCOT based on data contained in Initial, Final, True-Up or any Resettlement Statements.
>
> **TCR Invoice**
> An invoice issued to a successful bidder based on a final round of a TCR auction.

Invoice Recipient
Market Participants that receive an Invoice from ERCOT.

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Late Payment
Payments due to ERCOT by Invoice Recipients that are not received by the due date and time.

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

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 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 for the development and creation of 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
A QSE's ratio of Adjusted Metered Load to total ERCOT Adjusted Metered Load related to the appropriate interval.

Load Serving Entity
An Entity that provides electric service to Customers and Wholesale Customers. Load Serving Entities include Retail Electric Providers, Competitive Retailers, and Non-Opt In Entities that serve Load.

Local Congestion
Any Congestion that cannot be resolved by deployment of Balancing Energy Service by Congestion Zone. Local Congestion will include those actions, and related costs, associated with mitigating overloads on CSCs or CREs beyond that which can be accomplished by the zonal deployment of BES.

Location Code
The code representing the physical location of a Premise.

Low Operating Limit (LOL)
The minimum net capability of a Resource that may be delivered for a period of up to one hour.

Low Sustainable Limit (LSL)
The minimum net capability of a Resource that may be delivered for an indefinite period.

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Maintenance Outage
***See* Outage**

Market Clearing Price for Capacity
The highest price associated with a Congestion Zone for a Settlement Interval for Ancillary Service capacity awarded in each Ancillary Services capacity procurement run by ERCOT. There will be a separate Market Clearing Price for Capacity for each Ancillary Services capacity market.

Market Clearing Price for Energy
The highest price associated with a Congestion Zone for a Settlement Interval for Balancing Energy deployed during the Settlement Interval.

Market Implementation Plan
Plan developed by ERCOT that addresses training, testing, qualification, and registration of Market Participants for participation in the Customer Choice Pilot, as well as the conversion to single Control Area operations.

Market Information System (MIS)
An electronic communications interface established and maintained by ERCOT that provides a communications link to Market Participants, including secure access by and communications to individual Market Participants regarding information linked to each individual Market Participant.

Market Participant
An Entity that engages in any activity that is in whole or in part the subject of these Protocols, regardless of whether such Entity has executed an Agreement with ERCOT.

Market Segment
The Segments defined in Article 2 of the ERCOT Bylaws. The segments are:

(1) Independent REPs,

(2) Independent Generators,

(3) Independent Power Marketers,

(4) Investor Owned Utilities,

(5) Municipals,

(6) Cooperatives, and

(7) Consumers.

Mass Drop
The immediate cessation of service by a CR to all ESI IDs served by the CR.

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

Merit Order
The ranking of Resources as a direct function of the monetary bid from those resources.

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

[PRR807: Replace the above definition "Messaging System" with the following upon system implementation:]

Messaging System
The ERCOT-to-QSE communications system used to send, or make available, Real Time notices and Dispatch Instructions to the QSEs.

Meter Data Acquisition System
The system to obtain revenue quality meter data from ERCOT Polled Settlement meters and Settlement Quality Meter Data from the TDSP for settlement and to populate the Meter Data Aggregation System and ERCOT Data Archive.

Meter Data Exchange Format
The format for submitting meter data to, or receiving data from, ERCOT Settlement Agent.

Meter Data Request Format
The format for requesting Settlement Quality Meter Data from the ERCOT Settlement Agent.

Meter Reading Entity (MRE)
An Entity that is responsible for providing ERCOT with ESI ID level consumption data as defined in Texas SET and Protocols Section 19. This Entity must be a TDSP that is registered with ERCOT as prescribed in Protocols Section 10. In the case of an ERCOT Polled Settlement (EPS) Meter or ERCOT populated ESI ID data (such as generation 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.

Mismatched Schedule Processing Fee
The fee charged to a QSE that fails to correct a mismatched schedule in a timely manner.

Mothballed Generation Resource
A Generation Resource for which a Generation Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute an RMR Agreement, and for which the Generation Entity has not announced retirement of the Generation Resource.

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

Must-Run Alternative (MRA) Agreement
The contractual arrangement between ERCOT and a MRA Resource

Must-Run Alternative (MRA) Resource
A Resource that was selected through the planning process pursuant to Section 6.5.9.2, Exit Strategy from an RMR Agreement to provide steady-state or dynamic voltage support, stability or management of localized transmission constraints under first contingency criteria, as described in the Operating Guides, at a lower cost than an RMR Agreement.

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NOx Emissions Allowance Index Price (NOxEAIP)
The average of the bid/ask price for Nitrogen Oxide (NOx) emissions allowances in dollars per allowance, published for each Operating Day. The NOxEAIP will be obtained by ERCOT and will be based on daily index prices selected by ERCOT that are generally accepted in the industry and regularly published. ERCOT will disclose to Market Participants the source of its selected NOxEAIP, along with descriptions of the nature and derivation of the index as available from the publisher of the index. In the event that an ERCOT-selected index becomes unavailable or unsuitable for the intended purpose, ERCOT will select a substitute index source. ERCOT

will notify Market Participants of any change in the index, along with a description of the nature and derivation of the substitute index and a summary of the reasons for the change, at least thirty (30) days prior to the beginning of its use. However, in the event that thirty (30) days' notice cannot be given for any reason, ERCOT will notify Market Participants as far prior to use as practical.

The NOxEAIP for Saturdays, Sundays, holidays and other days for which there is no index published shall be based on the next published index after the Operating Day. In the event that the index is not published for more than two (2) days, the previous day published index will be used for the next applicable settlement and the next day published index will be used for true-up of the Final Statement.

Net Dependable Capability
Maximum sustainable capability of a Generation Resource as demonstrated by performance testing.

Net Generation
Gross generation minus station auxiliaries or other internal unit power requirements metered at or adjusted to the point of interconnection at the Common Switchyard.

New Renewable Facilities
Renewable energy generators placed in service on or after September 1, 1999. A New Facility includes the incremental capacity and associated energy from an existing Renewable Facility through repowering activities undertaken on or after September 1, 1999.

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

Non-Opt In Entity (NOIE)
An Electric Cooperative or Municipally Owned Utility that does not offer Customer Choice.

Non-Spinning Reserve Service (NSRS)
A service that is comprised of 30-Minute Non-Spinning Reserve Service (30MNSRS) and BES-Capable Non-Spinning Reserve Service (BESCNSRS).

> **30-Minute Non-Spinning Reserve Service (30MNSRS)**
> A service that is provided through utilization of the portion of Off-line generation capacity capable of being synchronized and ramped to a specified output level within thirty (30) minutes (or Load that is capable of being interrupted within thirty (30) minutes) and that is capable of running (or being interrupted) at a specified output level for at least one (1) hour. 30MNSRS is not capable of participating in the Balancing Energy Services market because it does not meet all of the qualifications of providing Balancing Energy Service Up within fifteen (15) minutes.

North American Electric Reliability Corporation
The national organization that is responsible for establishing standards and policies for reliable electric system operations and planning, or its successor.

Notice or Notification
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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Obligation
Total Obligations scheduled by a QSE that are comprised of energy Obligations and Ancillary Services Obligations where:

> **Energy Obligations =**
> Load + losses + energy sales + energy exports; and
>
> **Ancillary Services Obligations =**
> ERCOT allocated Ancillary Services Obligations (which may be self-arranged) + Ancillary Services sales (to ERCOT or to other QSEs).

Off-line
The status of Resources that are not synchronously interconnected to the ERCOT System.

On-line
The status of Resources that are synchronously interconnected to the ERCOT System.

Operating Condition Notice
The first of four possible levels of communication issued by ERCOT in anticipation of a possible emergency condition detailed in Section 5.6, Emergency and Short Supply Operation.

Operating Day
The actual day, including hours ending 0100 to 2400, during which energy is flowing.

Operating Guides
Guidelines approved by the ERCOT Board describing the reliability standards for ERCOT.

Operating Hour
The current clock hour.

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

Operating Plan
A plan developed by ERCOT to operate the ERCOT System in Real Time.

Operational Constraint
Anticipated or actual security violation or overload of a transmission element, based on actual network topology.

Operational Model
The transmission model based on actual network topology of the ERCOT System.

Out of Merit Order (OOM)
The selection of Resources for Ancillary Services that would otherwise not be selected to operate because of their place (or absence) in the bidding process for that service.

Outage
Removal of a Facility, or a portion of a Facility, from service to perform maintenance, construction or repair on the Facility for a specified duration.

Forced Outage
For a Transmission Facility, an Outage initiated by protective relay, or manually in response to an observation by personnel or the System Operator 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 un-controlled actions) of a 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.

Maintenance Outage
Removing Transmission Facility or Resource Facility equipment from service to perform work on specific Facility components that could be postponed briefly. Such work is required to prevent a potential Forced Outage or Forced Derate and cannot be postponed until the next Planned Outage. Such Maintenance Outages are classified as follows:

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

(2) **Level II Maintenance Outage –** Equipment that must be removed from service within seven (7) days to prevent a potential Forced Outage or Forced Derate; and

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

Planned Outage
Any major or minor Transmission Facility or Resource Facility equipment Outage, other than a defined Maintenance Outage, that is planned and scheduled in advance as submitted to ERCOT.

Out of Merit Capacity
Capacity provided by a Resource selected by ERCOT outside the bidding process to resolve a reliability or security event.

Out of Merit Energy
Energy provided by a Resource selected by ERCOT outside the bidding process to resolve a reliability or security event.

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

Physical Responsive Capability (PRC)
A representation of the total amount of system wide online capability that has a high probability of being able to quickly respond to system disturbances. The PRC shall be calculated by (i) determining each Resource meeting the requirements defined in the Operating Guides, (ii) determining for each Resource the lesser quantity of the latest Net Dependable Capability, the Resource Plan High Operating Limit (HOL), or the telemetered Real Time capability, (iii) multiplying the lesser quantity of each Resource by the Reserve Discount Factor (RDF), (iv) using that result to determine the amount of responsive reserve capability then available on each Resource, and (v) the sum, for all Resources, of the responsive reserve capability as determined for each Resource. The PRC shall be used by ERCOT to determine the appropriate Emergency Notification and Energy Emergency Alert (EEA) levels.

Postage Stamp Allocation
The pro rata allocation of charges (or payments), which spreads to designated, Entities based on a pro rata share (of actual or estimated consumption).

Power Generation Company
An Entity registered by the PUCT that: (1) generates electricity that is intended to be sold at wholesale; (2) does not own a transmission or distribution Facility in this state other than an essential interconnecting Facility, a Facility not dedicated to public use, or a Facility otherwise excluded from the PURA definition of “electric utility;” and (3) does not have a certificated service area, although its affiliated electric utility or transmission and distribution utility may have a certificated service area.

Power Marketer
An Entity that:

(1) Becomes an owner or controller of electric energy in this state for the purpose of buying and selling the electric energy at wholesale;

(2) Does not own generation, transmission, or distribution Facilities in this state;

(3) Does not have a certificated service area; and

(4) Has been granted authority by the Federal Energy Regulatory Commission to sell electric energy at market-based rates or has registered as a power marketer.

Pre-assigned Congestion Rights (PCRs)
Congestion Rights allocated prior to the annual TCR auctions to MOUs and ECs which own or have a long-term (greater than five years) contractual commitments, entered into prior to September 1, 1999, for annual capacity and energy from a specific remote Generation Resource.

Premise
A Service Delivery Point or combination of Service Delivery Points that are assigned a single Electric Service Identifier (ESI ID) for purposes of settlement and registration.

Price-to-Beat
The bundled rate a Retail Electric Provider that is affiliated with an Entity required to unbundle its electric services, and offer Customer Choice, must charge to residential and small commercial Customers upon initiation of Customer Choice, as further described in Section 39.202 of PURA and PUCT rules.

Primary Meter
The ERCOT approved, revenue-quality meter connected at an ERCOT approved interconnection point.

Prior Agreement
Any previous agreement between an Entity, its Affiliate(s) or its predecessor(s) in interest and ERCOT regarding performance under the ERCOT Protocols.

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).

Profile Type
***See* Load Profile Class**

Program Administrator
The Entity approved by the PUCT that is responsible for carrying out the administrative responsibilities related to the Renewable Energy Credit Programs as set forth in subsection (g) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

Proposal for Installation
A written proposal submitted by an Entity to ERCOT describing a proposal for the installation of additional Metering Facilities.

Proprietary Customer Information
Any information compiled by a Market Participant on a Customer in the normal course of 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 records, or any other information that a Customer has expressly requested not be disclosed. 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.

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

Protocol Implementation Plan
Plan developed by ERCOT that identifies any known differences between the ERCOT market operations system, power operations system, and settlement systems and these Protocols, and specifies a plan to conform such systems to these Protocols.

Provider of Last Resort (POLR)
The designated Competitive Retailer as defined in the PUCT Substantive Rules for default Customer service, and as further described in Section 15.1, Customer Switch of Competitive Retailer.

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QSE Operator
The person designated by the QSE to communicate with ERCOT on a twenty-four (24)-hour basis.

Qualified Scheduling Entity
A Market Participant that is qualified by ERCOT in accordance with Section 16, Registration and Qualification of Market Participants, to submit Balanced Schedules and Ancillary Services bids and settle payments with ERCOT.

Qualifying Facility
A qualifying cogenerator or qualifying small power producer according to regulatory qualification criteria as defined in PURA.

Quick Start Unit
Generation units that are not On-line, but are capable of producing energy within the next Settlement Interval.

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

Reactive Power Profile
***See* Voltage Profile**

Reactive Reserve
That reactive capability required to meet sudden loss of generation, Load or transmission capacity and maintain voltage within desired limits.

Real Time
The current instant in time.

Registered Market Participant
Entity that is registered with ERCOT to participate in the competitive market administered by ERCOT within the ERCOT Region. Registered Market Participants include those using statewide systems administered by ERCOT and may be non-ERCOT participants.

Registration Processing Period
Minimum amount of time the ERCOT registration system requires to process transactions. This period begins when ERCOT receives a registration transaction request and continues until the completion of the transaction.

Regulation Service
A service that is used to control the power output of Resources in response to a change in system frequency so as to maintain the target system frequency within predetermined limits.

Reliability Must Run (RMR) Service
The provision of generation capacity and/or energy resources from Reliability Must Run Unit or a Synchronous Condenser Unit.

Reliability Must Run (RMR) Unit
A Generation Resource unit operated under the terms of an Agreement with ERCOT that would not otherwise be operated except that they are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria.

Remedial Action Plan
Predetermined operator actions to maintain ERCOT Transmission Grid reliability during a defined adverse operating condition.

Renewable Energy Credit (REC)
A Renewable Energy Credit (REC) is a tradable instrument that represents all of the renewable attributes associated with one (1) 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.

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 REC 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 PURA §39.904 pursuant to subsection (h) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

Renewable Production Potential
The maximum generation in MWh/interval from an Uncontrollable Renewable Resource that could be generated from all available units of such Resource. The Renewable Production Potential depends on the renewable energy that can be generated from the available units (wind or solar radiation) and the energy conversion characteristics of each unit. The Renewable Production Potential will be determined from data submitted in accordance with procedures established by ERCOT.

Replacement Reserve Service
A service that is procured from Generation Resource units planned to be Off-line and Load acting as a Resource that are available for interruption during the period of requirement.

Representative Interval Data Recorder
The technique for profiling premises participating in special pricing programs which consists of implementing a statistically representative Load research sample on the program population. The sample data is then used to develop the representative IDR (RIDR) for profiling these premises.

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 ROS.

Resettlement Statement
***See* Settlement Statement**

Resource
Facilities capable of providing electrical energy or Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System, as described in Section 6, Ancillary Services. This includes Generation Resources, Loads acting as Resources and Emergency Interruptible Load Service Resources.

Resource Category Generic Fuel Cost (RCGFC)
A standard $/MWh cost for fuel specific to one of eight resource categories (Nuclear, Hydro, Coal and Lignite, Combined Cycle, Simple Cycle, Gas Steam, Diesel and Non-Hydro Renewable).

Resource Category Generic Startup Cost
A fixed price for starting a unit that is selected out of merit order to provide balancing energy. The RCGSC is defined by the generation unit category (Base-load, Gas Intermediate, Gas Cyclic, Gas Peaking and Renewable).

Resource Category Generic Operational Cost
A standard $/MWh price for running a unit selected out of merit order to provide balancing energy. The RCGOC is defined by the generation unit category (Base-load, Gas Intermediate, Gas Cyclic, Gas Peaking and Renewable).

Resource Entity
A Market Participant that owns or controls a Resource.

Resource ID
A unique identifier assigned to each Resource used in the registration and settlements systems managed by ERCOT.

Resource Minimum Down Time
The minimum time from shutdown of a Resource required until that Resource can be restarted and available to the ERCOT market.

Resource Plan
A plan provided by a QSE to ERCOT indicating the forecast state of Generation Resources or individual Loads each acting as a Resource, including information on availability, limits and forecast generation or Load of each Resource.

Responsibility Transfer
The controlled and orderly transfer of eligible resources from one QSE to another in accordance with Section 4, Scheduling.

Responsive Reserve Service
Responsive Reserve consists of the daily operating reserves that are intended to help restore the frequency of the interconnected transmission system within the first few minutes of an event that causes a significant deviation from the standard frequency.

Retail Business Day
***See* Business Day**

Retail Business Hour
Any hour within a Retail Business Day.

Retail Electric Provider
A person that sells electric energy to retail Customers in this state. As provided in PURA §31.002(17), a Retail Electric Provider may not own or operate generation assets. As provided in PURA §39.353(b), a Retail Electric Provider is not an Aggregator.

Retail Entity
Municipally Owned Utilities (MOUs), generation and transmission cooperatives, and distribution cooperatives that offer customer choice; Retail Electric Providers (REPs); and Investor Owned Utilities (IOUs) that have not unbundled pursuant to PURA §39.051.

Revenue Quality Meter
For ERCOT Metered Entities, a meter that is in compliance with the Protocols and the Operating Guides. For TDSP Metered Entities, a meter that is in compliance with Local Regulatory Authority approved meter standards or the Protocols and the Operating Guides.

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Sample Design
The processes by which ERCOT determines the appropriate requirements for a sample of Customer Premises which requirements will be used to create a Load Profile.

Sample Size
The number of data points (i.e. Customer Premises) in a particular sample.

Sampling
The process of selecting a subset of a population of Customers that statistically represents the entire population.

Schedule Control Error
The difference in the QSE's actual Resource output and its base power schedule plus instructed Ancillary Services.

Scheduling Process
The process through which schedules for energy and Ancillary Services are submitted by QSEs to ERCOT as further described in Section 4, Scheduling.

Season
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.

Segmentation
The process of dividing a population into a number of sub-sets, according to certain parameters, for the purpose of creating Load Profiles for sub-sets of the population.

Segmentation Parameter
The parameter chosen as the basis for Segmentation.

Self-Arranged Ancillary Service
Resources used for Ancillary Services designated by a QSE for use by ERCOT for meeting the ERCOT allocated portion of the Ancillary Services Obligations of a QSE. These Resources may not be included in the ERCOT Ancillary Services market.

Service Address
The street address associated with an ESI-ID as recorded in the Registration Database. This address shall conform to United States Postal Service Publication 28.

Service Delivery Point
The specific point on the TDSP's system where electricity flows from the TDSP to a Load.

Service Fee Schedule
A listing of ERCOT fees and charges to Market Participants, posted on the Market Information System.

Service Filing
A filing by a QSE to ERCOT as part of the QSE's certification process, as defined in Section 16, Registration and Qualification of Market Participants.

Settlement Calendar
As defined in Section 9.1.2, Settlement Calendar.

Settlement Interval
The time period for which a Market Service is deployed and financially settled. For example, the currently defined settlement interval for the Balancing Energy Market Service is 15 minutes.

Settlement Invoice
***See* Invoice**

Settlement Meter
Generation and end-use consumption meters used for allocation of ERCOT charges and wholesale and retail settlements.

Settlement Quality Meter Data
Data that has been edited, validated, and is appropriate for ERCOT Settlement Agent 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.

Initial Statement
The first iteration of a Settlement Statement issued for a particular Operating Day, as further described in Section 9.2.3, Initial Statements.

Final Statement
The statement issued at the end of the fifty-ninth (59th) calendar day following the Operating Day, as described in 9.2.4, Final Statements.

Resettlement Statement
The statement using corrected settlement data, in accordance with Section 9.2.5, Resettlement Statement.

True-Up Statement
The statement issued six (6) months following the Operating Day, as further described in Section 9.2.6, True-Up Statement.

Shadow Price
The cost of an operation to effect a one (1) MW change in a constraint.

Shift Factor
A measure of the flow of a unit injection of the power on the transmission element from a particular bus to a fixed reference bus.

Site Specific Shift Factor
The actual Shift Factor for a particular bus.

Zonal Shift Factor
The average Shift Factor for all busses in a particular zone.

Sign/Direction Terminology Conventions for Reactive Power

Generator
Lagging power factor operating condition is when volt-ampere reactive (VAR) flow is out of the Generation Resource unit (overexcited generator) and into the transmission system and is considered to be positive (+) flow, i.e., in the same direction as megawatt power flow. The generator is producing megavolt-amperes reactive.

Leading power factor operating condition means that VAR flow is into the Generation Resource unit (underexcited generator) and out of the transmission system and is considered to be negative (–) flow, i.e., in the opposite direction as megawatt power flow. The generator is absorbing megavolt-amperes reactive.

Transmission Line Terminal
VAR flow out of the bus and into the line is considered to be positive (+) flow. VAR flow into the bus and out of the line is considered to be negative (–) flow.

Capacitor
Produces reactive power (VAR source) for voltage control and causes the system power factor to move towards a leading condition.

Reactor
Absorbs reactive power (VAR sink) for voltage control and causes the system power factor to move towards a lagging condition.

Startup Loading Failure
An event that results when a Generation Resource is unable to be at Low Sustainable Limit (LSL) at the time scheduled in the Resource Plan which occurs while the unit is ramping up to its scheduled MW output. A Startup Loading Failure ends when the Resource: (1) achieves its LSL; (2) is scheduled to go Off-line; or (3) enters a Forced Outage.

Supply
Total supply scheduled by a QSE that is comprised of Energy Supply and Ancillary Services Supply where:

Energy Supply =
Resources + energy purchases + energy imports; and

Ancillary Services Supply =
Resources + Ancillary Services purchases (including purchases through ERCOT) + Ancillary Services imports.

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 Resource
A Generation Resource that can be connected to either the ERCOT Transmission Grid or a grid outside the ERCOT Region.

Synchronous Condenser Unit
A unit operated under the terms of an annual Agreement with ERCOT that is only capable of supplying Volt Amperes Reactive (VAR) that would not otherwise be operated except that it is necessary to provide voltage support under first contingency criteria.

System Benefit Fund
The fund established by the PUCT to provide funding for Customer education programs, programs to assist low-income electric Customers; and the property tax replacement mechanism provided by Section 39.601 of PURA.

System Congestion Fund
ERCOT's accounting fund from which payments for resolving Congestion are disbursed and to which ERCOT credits Congestion-related receipts from QSE's representing Loads.

System Operator
An Entity supervising the collective Transmission Facilities of a power region that is charged with coordination of market transactions, system-wide transmission planning, and network reliability.

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TCR Interface
The CSC for which Transmission Congestion Rights are auctioned and awarded.

TCR Invoice
See Invoice

TDSP Metered Entity
Any Entity that meets the requirements of Section 10.2.2, TDSP Metered Entities.

Technical Advisory Committee
A subcommittee in the ERCOT governance structure reporting to the Board of Directors as defined by the ERCOT bylaws.

Texas Regional Entity (TRE)
The organization approved by the Electric Reliability Organization and the FERC to perform the regional Entity functions for the ERCOT Region described in the Electricity Modernization Act of 2005 (16 U.S.C. §824 et seq.).

Texas SET
Texas Standard Electronic Transaction procedures, set forth in Section 19, Texas SET, used to transmit information pertaining to the Customer Registration Database. Record and Data Element Definitions are provided in the data dictionary in Protocols Section 19.

Time of Use Metering
A programmable electronic device capable of measuring and recording electric energy in pre-specified time periods. For Load Profiling purposes Time of Use Metering does not include IDRs.

Time of Use Schedule
A schedule identifying the Time of Use period associated with each Settlement Interval. These schedules may include on-peak, off-peak, and shoulder periods.

Total Energy Obligation
The total energy Obligation for a Qualified Scheduling Entity during a Settlement Interval, including the energy from the Balanced Schedule and integrated energy of instructed Ancillary Services.

Total Transmission Capacity
The maximum power that may be transferred across a transmission corridor while maintaining reliability of the ERCOT System.

Transaction Clearinghouse
A batch, transactional interface intended to provide reliable exchange of high volume, standardized transactions between Market Participants and ERCOT using the Texas SET procedures in Section 19, Texas SET.

Translation Factor
The monthly ratio of the aggregate Competitive Retailer's four (4) coincident peak demand over the monthly aggregate Competitive Retailer's coincident peak demand, as further described in Section 9.8, Transmission Billing Determinant Calculation.

Transmission Access Service
Use of the TDSP's Transmission Facilities for which the TDSP is allowed to charge for the use through tariff rates approved by the PUCT.

Transmission Billing Determinants
Key parameters and formula components required by a TDSP in determining the billing charges for the use of its Transmission Facilities and/or distribution Facilities.

Transmission Congestion Right (TCR)
A financial hedge against the cost of 1 MW flowing across a particular Commercially Significant Constraint, in a single direction, for 1 hour.

Transmission Congestion Right Account Holder (TCR Account Holder)
A Registered Market Participant that is qualified to bid for and own TCRs in ERCOT's annual or monthly auctions, or that has acquired such rights in secondary markets for purposes of participating in ERCOT's financial settlements for Congestion Credits. [A TCR Account Holder is a Registered Market Participant whose record of ownership appears in ERCOT's databases of auction results or financial settlements for Zonal Congestion Credits].

Transmission and/or Distribution Service Provider (TDSP)
An Entity that owns or operates for compensation in this state, equipment or Facilities to transmit and/or distribute electricity, and whose rates for Transmission Service, distribution service, or both is set by a Governmental Authority or an Entity that was selected to own and operate Transmission Facilities listed in the Public Utility Commission of Texas (PUCT) Order in Docket No. 35665, Commission Staff's Petition for the Selection of Entities Responsible for Transmission Improvements Necessary to Deliver Renewable Energy from Competitive Renewable Energy Zones, which has a code of conduct approved by the PUCT.

Transmission Facilities
The following Facilities are deemed to be Transmission Facilities:

(1) Power lines, substation, and associated Facilities, operated at 60 kV or above, including radial lines operated at or above 60 kV.

(2) Substation Facilities on the high 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.

(3) The direct current interconnections with the Southwest Power Pool (SPP), Western System Coordinating Council (WSCC), Comision Federal de Electricidad, or other interconnections.

Transmission Loss Factors
The fraction of ERCOT Load (forecast or actual) that is considered to constitute the ERCOT Transmission Grid losses in the Settlement Interval. Transmission Loss Factors are computed by ERCOT and are based on a linear interpolation (extrapolation) of the calculated losses in the off-peak and on-peak seasonal ERCOT base cases.

Transmission Losses
Difference between energy input into the ERCOT Transmission Grid and the energy taken out of the ERCOT Transmission Grid.

Transmission Service
Commercial use of Transmission Facilities.

Transmission Service Provider
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.

True-Up Statement
***See* Settlement Statement**

Two-Day Ahead
The twenty-four (24) hour period beginning the instant after 2400 forty-eight (48) hours before the Operating Day.

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Unaccounted for Energy (UFE)
The difference between total metered Load each Settlement Period, adjusted for applicable Distribution Losses and Transmission Losses, and total ERCOT System net generation.

Uncontrollable Renewable Resources
Generators that can only produce an amount of energy directly related to their supply of variable energy from their respective renewable resources, such as wind or solar.

Uninstructed Deviation
A condition occurring whenever the total metered resources of a QSE for a Settlement Interval are different from the total of the scheduled resources plus any Resource deployments instructed by ERCOT.

Uninstructed Factor
A factor used to reduce the total payments made to a Resource for Uninstructed Deviations. The Uninstructed Factor could change by interval, in accordance with Section 6.8.1.14.2, Determining the Uninstructed Factor.

Unusual Event
Specifics events, as defined in these Protocols Section 4, Scheduling, that allow ERCOT to deploy Balancing Energy Service outside of the normal deployment notification.

Uplift
The process of allocating costs to QSEs based on Loads and exports within the ERCOT Region.

Usage Profile
***See* Load Profile**

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Validation, Editing, Estimation of Meter Data
See Section 11, Metering

Virtual QSE
An LSE whose QSE has provided notice of its intent to terminate its relationship with the LSE and who then fails to meet ERCOT's creditworthiness requirements to become an Emergency QSE, as set forth in Section 16.2.13.1, Designation as an Emergency QSE or Virtual QSE.

Voltage Profile
A predetermined distribution of desired nominal voltage set points across the ERCOT System.

Voltage Support Service
A 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 four possible levels of communication issued by ERCOT in anticipation of a possible emergency condition detailed in Section 5.6, Emergency and Short Supply Operation.

Weather Zone
A geographic region in which climatological characteristics are similar for all areas within such region.

Wholesale Customers
Non-Opt-in entities receiving service at wholesale points of delivery from an LSE other than themselves.

Wind-powered Generation Resource (WGR)
A Generation Resource that is powered by wind.

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 eighty-percent (80%) probability of exceedance of the Total ERCOT Wind Power Forecast.

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Zonal Congestion
Congestion on CSCs or CREs that can be resolved by zonal deployment of Balancing Energy Services and RPRS.

Zonal Congestion Credits
Payments equal to the directly assigned costs of BES and RPRS that were incurred in managing Zonal Congestion. Zonal Congestion Credits are paid to TCR Account Holders, appearing in ERCOT's database, as the owner of record for the hour of relevant Settlement Intervals.

2.2 Acronyms

30MNSRS	30-Minute Non-Spinning Reserve Service
AAA	American Arbitration Association
ADR	Alternative Dispute Resolution
ADU	Adjusted Daily Usage
AEIC	Association of Edison Illuminating Companies
AGC	Automatic Generation Control
AML	Adjusted Metered Load
AMR	Adjusted Metered Resource
AMS	Advanced Metering System
AP	Adjustment Period
API	Automated Programmatic Interface
ARR	Adjusted RPS Requirement
AS	Ancillary Service
ATC	Available Transmission Capability
AVR	Automatic Voltage Regulator
BESCNSRS	BES-Capable Non-Spinning Reserve Service
BLT	Block Load Transfer
BSS	Black Start Service
CAO	Control Area Operator
CCF	Capacity Conversion Factor
CFC	Constant Frequency Control
CFE	Comision Federal de Electricidad
COP	Current Operating Plan
CPT	Central Prevailing Time
CR	Competitive Retailer
CRE	Closely Related Elements
CSA	Continuous Service Agreement
CSC	Commercially Significant Constraint
CSV	Comma Separated Values
CT	Current Transformer
DA	Day Ahead
DAS	Data Aggregation System
DC	Direct Current
DLC	Direct Load Control
DLF	Distribution Loss Factor
DOE	Department of Energy
DRG	Distributed Renewable Generation
DSA	Dynamic Security Analysis
DSG	Dynamically Scheduled Generation
DSL	Dynamically Scheduled Load
DSP	Distribution Service Provider
DUNS #	DUNS Number
EC	Electric Cooperative
EDI	Electronic Data Interchange
EEA	Energy Emergency Alert

PUBLIC

EILS	Emergency Interruptible Load Service
EMS	Energy Management System
EPS	ERCOT Polled Settlement Meter
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESC	Engineering Subcommittee
ESI ID	Electric Service Identifier
ETIN	Electronic Transmission Information Network
EWG	Exempt Wholesale Generators
FERC	Federal Energy Regulatory Commission
FIP	Fuel Index Price
FOP	Fuel Oil Price
FPA	Federal Power Act
FPC	Federal Power Commission
FRR	Final RPS Requirement
FTC	Federal Trade Commission
FTP	File Transfer Protocol
GR	Generation Resources
HO	Historical Output
HOL	High Operating Limit
HSL	High Sustainable Limit
HVDC	High Voltage Direct Current
IDR	Interval Data Recorder
IOU	Investor Owned Utilities
IPP	Independent Power Producers
KWH	Kilowatt Hour
LOL	Low Operating Limit
LPA	Load Profiling Agent
LSE	Load Serving Entity
LSL	Low Sustainable Limit
MAD	Mean Absolute Deviation
MAPE	Mean Absolute Percentage Error
MCP	Market Clearing Price
MCPC	Market Clearing Price for Capacity
MCPE	Market Clearing Price for Energy
MDAS	Meter Data Acquisition System
MIS	Market Information System
MOS	Market Operating System
MOU	Municipally Owned Utility
MP	Market Participant
MRA	Must-Run Alternative
MRE	Meter Reading Entity
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
NBS	National Bureau of Standards

NERC	North American Electric Reliability Corporation
NOIE	Non Opt-In Entity
NSRS	Non-Spinning Reserve Service
NWSIDR	Non-Weather-Sensitive Interval Data Recorder
OC	Operational Congestion
OCN	Operating Condition Notice
Off-line BESCNSRS	BES-Capable Off-line Non-Spinning Reserve Service
On-line BESCNSRS	BES-Capable On-line Non-Spinning Reserve Service
OOM	Out of Merit Order
OOME	Out of Merit Energy
OOMC	Out of Merit Capacity
OTC	Operating Transmission Capacity
PCR	Pre-assigned Congestion Right
PM	Power Marketer
POLR	Provider of Last Resort
POS	Power Operating System
PRC	Physical Responsive Capability
PRR	Protocol Revision Request
PTB	Price to Beat
PUCT	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act, Title II, Texas Utility Code
PURPA	Public Utility Regulatory Policy Act
PV	PhotoVoltaic
QSE	Qualified Scheduling Entity
RA	Registration Agent
RAP	Remedial Action Plan
RAPP	Registration Agent Processing Period
RCAG	Remote Control Area Generator
RCAL	Remote Control Area Load
RDF	Reserve Discount Factor
REC	Renewable Energy Credit
REP	Retail Electric Provider
RGS	Regulation Service
RGSD	Regulation Service Down
RGSU	Regulation Service Up
RID	Resource ID
RIDR	Representative IDR
RMR	Reliability Must-Run
RPP	Registration Processing Period
RPS	Renewable Portfolio Standard
RPRS	Replacement Reserve Service
RRO	Responsive Reserve Obligation
RRS	Responsive Reserve Service
RRWF	Rapid Response Wind Farm
RspT	Responsibility Transfer
RSS	Reliability and Security Subcommittee

RT	Real Time
SCADA	Supervisory Control And Data Acquisition
SCE	Schedule Control Error
SCF	System Congestion Fund
SDP	Service Delivery Point
SET	Standard Electronic Transaction
SGIA	Standard Generation Interconnection Agreement
SIS	Security Information System
SPP	Southwest Power Pool
SRR	Statewide RPS Requirement
SRWF	Slow Response Wind Farm
TAC	Technical Advisory Committee
TCOS	Transmission Cost of Service
TCR	Transmission Congestion Right
T&D Losses	Transmission Losses & Distribution Losses
TDSP	Transmission and/or Distribution Service Provider
TEWPF	Total ERCOT Wind Power Forecast
TLF	Transmission Loss Factor
TMOS	Transmission Market Operations Subcommittee
TOU	Time Of Use
TOUS	Time Of Use Schedule
TRE	Texas Regional Entity
TSP	Transmission Service Provider
TTC	Total Transfer Capability
TUOS	Transmission Use of Service
TX SET	Texas Standard Electronic Transaction
UFE	Unaccounted For Energy
URL	Unit Reactive Limit
USTR	Uninitiated Service Termination Request
Va.m.M	Vector Absolute Megawatt-Mile
Va.m.O	Vector Absolute Megawatt Ohm
VEE	Validation, Editing and Estimation of meter data
VSA	Voltage Security Analysis
VSS	Voltage Support Service
VT	Voltage Transformer
WGR	Wind-powered Generation Resource
WGRPP	Wind-powered Generation Resource Production Potential
WSCC	Western System Coordinating Council
WSIDR	Weather-Sensitive Interval Data Recorder
XML	Extensible Markup Language

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ERCOT Protocols
Section 3: Open Access to the ERCOT Transmission Grid

January 5, 2001

3 OPEN ACCESS TO THE ERCOT TRANSMISSION GRID

3.1 Overview

Open access to the ERCOT Transmission Grid will be provided to all Eligible Transmission Service Customers by Transmission Service Providers (TSPs) and ERCOT in accordance with these protocols and the PUCT Substantive Rules, Chapter 25, Subchapter I, Transmission and Distribution.

3.2 Eligibility for Transmission Service

Transmission Service is available to all Eligible Transmission Service Customers. Energy may be transmitted and Ancillary Services may be provided on behalf of an Eligible Transmission Service Customer through the ERCOT System only if scheduled through a Qualified Scheduling Entity ("QSE").

3.3 Nature of Transmission Service[1]

Transmission Service allows all Eligible Transmission Service Customers to deliver Energy from Resources to serve Load obligations, using the Transmission Facilities of all of the Transmission Service Providers in ERCOT. ERCOT shall ensure the scheduling of Energy and Ancillary Services into, out of or through the ERCOT Transmission Grid on behalf of all Eligible Transmission Service Customers subject to the provisions stated in these Protocols.

3.4 Payment for Transmission Access Service

ERCOT will not collect Transmission Access Service fees for the TSP’s cost of service. ERCOT will provide volumetric data, pursuant to Section 9, 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 Services is addressed separately in these Protocols.

3.5 Interconnection of New Generation

Interconnection of new Generation Resources to the ERCOT Transmission Grid shall be in accordance with the ERCOT Standard Generation Interconnection Agreement (SGIA) and ERCOT SGIA Procedures.

[1] PUCT Rules, Ch. 25, Section 25.191.

ERCOT Protocols
Section 4: Scheduling

July 1, 2009

4 SCHEDULING

4.1 Overview of the Scheduling Process

4.1.1 Day Ahead Scheduling Process

Time Period at or before:	Qualified Scheduling Entity (QSE) Submission:	ERCOT Action:
Day Ahead		
0600		• Publish updated transmission system information, Load Forecasts (Congestion Zone, and by total ERCOT Transmission System), Ancillary Service (AS) Plan, AS responsibility, mandatory decremental Balancing Energy Service bid percentage requirements and Transmission Loss Factors (TLFs) and Distribution Loss Factors (DLFs).
1100	• Balanced Energy Schedule of Obligations and Resources. • Self-Arranged AS schedule.	• Validate schedules and notify affected QSEs of any invalid or mismatched schedules.
1115	• Resubmit corrected schedules.	• Review schedules: Commercial Model. • Commercially Significant Constraint (CSC) Congestion. • Notify QSEs of Congested CSCs. • Post schedule impact on CSCs. • Notify QSEs of any difference in ERCOT's zonal Load forecast and the aggregate of QSE schedules in a zone.
1300	• Update Balanced Energy Schedule of Obligations and Resources. • Update Self-Arranged AS schedule • AS bids to supply AS to ERCOT AS Market.	• Validate schedules and notify affected QSEs of any invalid or mismatched schedules.
1315	• Resubmit corrected updated schedules.	• Validate resubmitted schedules and adjust as necessary.
1330		• Purchase AS through ERCOT AS Market in order to complete ERCOT's Day Ahead AS plan. • Review Day Ahead Market Clearing Prices for Capacity (MCPCs) for each Day Ahead AS market operated by ERCOT.
1500	• Submit updated AS schedule that includes self-arranged and AS bids selected by ERCOT.	• Review and validate AS schedules as necessary.

1600	• Submit Resource Plans with unit-specific information. • Submit Replacement Reserve Service (RPRS) bids. • Adjust AS schedule to show only 30-Minute Non-Spinning Reserve Service (30MNSRS) according to ERCOT procedure.	• Verify that Resource Plans are sufficient to meet the QSE schedule. If not, ERCOT will notify the QSE.
By 1800		• Evaluate Resource Plans to determine system security. • Evaluate RPRS needed to correct CSC, and Operational Congestion (OC) – Operational Model, and capacity insufficiency.
By 1800		• Create Merit Order of RPRS by zone or Operational Constraint as applicable.
By 1800		• Determine MCPC for RPRS by zone as applicable.
By 1800		• Close and clear Day Ahead RPRS market.
After 1800	• Modify RPRS bids.	

4.1.2 Adjustment Period Scheduling Process

The Adjustment Period (AP) Scheduling Process will follow the following timeline with time T being the start of the Operating Hour:

Adjustment Period	**QSE Responsibility:**	**ERCOT Responsibility:**
Time = T minus 60 minutes	• Submit updated Balanced Schedule of Obligations and Supply for the hour beginning at Time T, and any hour after T. • Submit bids for Balancing Energy including any mandatory decremental Balancing Energy bids and any mandatory Balancing Energy bids for Non-Spin obligations. • Submit updated Self-Arranged AS schedule for the hour beginning at Time T and any hour after Time T (the amount of Self-Arranged AS may not change from Day Ahead, however, the Resources supplying the Self-Arranged AS may be altered. If ERCOT calls on additional AS in the AP, the allocated portion of the additional AS may be self-arranged). • Submit updates to Resource Plan. • Submit bids for RPRS. • Submit bids for additional Ancillary Services. • Submit bids for incremental and decremental Resource specific premiums.	• Review updated Balanced Schedule. • Review updated Resource Plans. • Review updated Self-Arranged AS schedule. • Validate schedules and notify affected QSEs of any invalid or mismatched schedules. • Identify CSC Congestion or OC or capacity insufficiency.
Time = T minus 45 minutes	• Resubmit corrected schedules.	

4.2 Scheduling-Related Duties of ERCOT

ERCOT is responsible for administering the Day Ahead and Adjustment Period Scheduling Processes through which final schedules for energy and Ancillary Services are submitted by QSEs and a Current Operating Plan is developed for use in operating the ERCOT System in Real Time. To fulfill its responsibilities with respect to providing information to the market necessary for QSEs to schedule energy and Ancillary Services, ERCOT shall:

(1) Post forecasted ERCOT System conditions and Load for the next seven (7) days, by hour, by Congestion Zone. ERCOT will also post any area Load forecasts that were used to create the system Load forecast;

(2) Post forecasted Transmission Loss Factors and Distribution Loss Factors;

(3) Post Load Profiles for non-IDR metered Customers;

(4) Validate the QSEs' energy schedules and make adjustments as necessary in accordance with the validation process;

(5) Validate the QSEs' Ancillary Service schedules and Self-Arranged Ancillary Service Resources;

(6) Only accept schedules from a QSE; and

(7) Require all Loads and Resources be represented by a QSE.

4.3 Scheduling-Related Duties of Qualified Scheduling Entities

QSE scheduling responsibilities are set forth below.

4.3.1 Functions and Activities

QSEs must submit schedules that identify Obligations and Supply and their associated Congestion Zones. QSEs must submit Balanced Schedules for each Settlement Interval. For a Schedule to be balanced, Total Energy Obligation must equal total Energy Supply and total Ancillary Services Obligation for each service type must meet total Ancillary Services Supply for each service type.

It is necessary to balance Ancillary Services schedules, as well as, Energy Schedules. In order to do so, the QSE must indicate on its schedule the amount of Ancillary Services that will be purchased from the ERCOT Ancillary Services Market.

4.3.2 Schedule Components

Included in each Balanced Schedule is:

(1) Energy to be produced by Resources that the QSE represents, by Congestion Zone;

(2) Energy to be consumed by Loads that the QSE represents (including T&D Losses) by Congestion Zone;

(3) ERCOT allocated Ancillary Services Obligations for the QSE;

(4) Any energy and Ancillary Services scheduled to or from other QSEs (e.g. Inter-QSE Trades);

(5) Any Balancing Energy scheduled through the ERCOT Scheduling Process; and

(6) Any Self-Arranged Ancillary Services.

When relaxed Balanced Schedules are allowed by ERCOT, pursuant to Section 4.3.5, Requirement for Balanced Schedules, the requirement for subpart (2) above shall be relaxed and QSEs shall be allowed to schedule energy for Load that is equivalent to the amount of scheduled energy for Resources as specified in subpart (1) and (5) above.

Use of Balancing Energy scheduled via ERCOT to meet Obligations shall be limited to an amount supported by the QSE's credit collateral with ERCOT.

4.3.3 Special Scheduling Considerations for Split Generation Meters

When a generation meter is split, as provided for in Section 10, Metering, two or more independent virtual generating units may be created for purposes of scheduling, ERCOT System operation, and settlement.

Each virtual generator unit may be scheduled by a different QSE. A QSE may only schedule up to the fixed ownership percentage of the actual generator's maximum output.

Each QSE will be responsible for including the virtual generator portion in its Resource Plan. A QSE's Ancillary Services capacity will be bid for the jointly-owned unit on the basis of a fixed ownership percentage that is shown in the registration database.

ERCOT will handle scheduling discrepancies in the same manner as other units.

4.3.4 Operations of the Qualified Scheduling Entity

Scheduling Center Requirement. A QSE shall maintain a 24-hour, seven-day-per-week scheduling center with qualified personnel for the purposes of communicating with ERCOT for scheduling purposes and for deploying the QSE's Ancillary Services in Real Time.

QSE Representative. Each QSE shall, for the duration of the Scheduling Process and settlement period for which the QSE has submitted schedules to ERCOT, designate a representative who shall be responsible for operational communications and who shall have sufficient authority to commit and bind the QSE.

4.3.5 Requirement for Balanced Schedules.

A QSE shall submit to ERCOT only Balanced Schedules, for both energy and Ancillary Services, in the Day Ahead Scheduling Process and the Adjustment Period. If a QSE submits a schedule that is not a Balanced Schedule, ERCOT shall reject that schedule in accordance with Section 4.4.13, ERCOT Day Ahead Ancillary Services Procurement Process.

QSE s may relax their Balanced Schedules by projecting interval Supply and setting aggregate Obligations equal to aggregate Supply, however, Inter-QSE Trades must still match in accordance with Section 4.7.2, Schedule Validation Process. ERCOT Operations may commit

Resources, as required, to maintain the balance of Loads and Resources on a system-wide and zonal basis; including, but not limited to, the commitment of Replacement Reserves, following the Day-Ahead and during the Adjustment Period, to assure the adequacy of Balancing Energy Services.

4.4 Day Ahead Scheduling Process

4.4.1 Overview

ERCOT will implement, as described in this Section, the Day Ahead Scheduling Process, which begins at 0600 and ends at 1800. All ERCOT schedules, notices and other information requiring publication under this Section shall be published on the Market Information System (MIS) as set forth in Section 12 of these Protocols.

4.4.2 Posting of Forecasted ERCOT System Conditions

No later than 0600 in the Day Ahead ERCOT shall post the following information for each hour of the Operating Day:

(1) A forecast of conditions on the ERCOT System, including known transmission line and other Transmission Facility Outages;

(2) A forecast of Total Transfer Capability including any relevant information describing forecasted transfers for each CSC.

(3) Weather assumptions used by ERCOT to forecast ERCOT System conditions.

4.4.3 Notification to the Market of ERCOT's Day Ahead Ancillary Services Plan

Before 0600 of the Day Ahead, ERCOT will analyze the next day's expected Load conditions and develop a Day Ahead Ancillary Services Plan that identifies the amount of each Ancillary Service necessary for each hour of the next day. If ERCOT determines that an Emergency Condition may exist that would adversely impact system reliability, it may change the percentage of Loads acting as Resources that will be allowed to provide Responsive Reserve Service from the monthly amounts determined previously, as described in Sections 6.4.1 (2) and (3). Any change in the percentage will be communicated by ERCOT to the market before 0600 of the Day Ahead.

4.4.4 Notification to QSEs of Ancillary Service Obligations

ERCOT will notify QSEs by 0600 of the Day Ahead of the QSE's Day Ahead Ancillary Service Obligations. The Day Ahead Ancillary Service Obligation will be assigned to each QSE by multiplying the ERCOT Obligation by the sum of the Load Ratio Shares, rounded to no fewer than six (6) decimal places, for the LSEs that a QSE represents.

4.4.5 Notification to QSEs of Mandatory Balancing Energy Service Down Bid Percentage Requirements

ERCOT will make available via a programmatic interface and post by 0600 of the Day Ahead the percentage of mandatory Balancing Energy Service Down bids required by Congestion Zone for each hour of the Operating Day for each QSE. If ERCOT changes the percentage requirement for any hour for any Congestion Zone from the previous Operating Day, only then will ERCOT notify all QSEs by 0600 of the Day Ahead of the QSE's percentage requirement for Balancing Energy Service Down bids by Congestion Zone for each hour of the Operating Day. The percentage of mandatory Balancing Energy Service Down bids required will be the same for all QSEs, but will not apply to energy scheduled by ERCOT from Resources under an RMR Agreement.

4.4.6 Notification to QSEs of Transmission Loss Factors and Distribution Loss Factors

ERCOT will make available via a programmatic interface and post by 0600 of the Day Ahead of the estimates for ERCOT-wide Transmission Loss Factors for each Settlement Interval of the Operating Day.

By 0600 ERCOT will also make available via a programmatic interface and post the Distribution Loss Factors, as provided by the DSPs, for each Settlement Interval of the Operating Day for each DSP.

4.4.7 Update of Forecasted ERCOT System Conditions

At 0600 of the Day Ahead, ERCOT shall update and publish the forecasted ERCOT System conditions, including: total forecast system Load, and Load forecasts for each Congestion Zone. ERCOT shall also update and provide this information periodically throughout the day, as forecasts and system conditions change.

4.4.8 Submittal of Day Ahead Schedules and Ancillary Services Schedules

QSEs will submit Day Ahead Balanced Schedules to ERCOT before 1100 of the Day Ahead for each Settlement Interval of the Operating Day. Obligations and Supply must be scheduled by Congestion Zone. Although the schedules must be balanced, they need not be balanced by Congestion Zone.

The QSE's balanced Ancillary Service schedule must specify the amount of ERCOT allocated Ancillary Service Obligation for each service type that the QSE intends to purchase from ERCOT.

Day Ahead schedules may also include Self-Arranged Ancillary Services in accordance with Section 6.2.2, provided by the QSE to meet all or a portion of its Ancillary Services Obligation. Self-Arranged Ancillary Services may consist of groups of Resources, specific Resources, or trades with other QSEs. After 1100, a QSE may not increase its level of Self-Arranged Ancillary

Services for the Day Ahead Obligations, unless ERCOT has notified Market Participants of CSC Congestion or capacity insufficiency as described in Section 4.4.9. If such Notice is provided, then the QSE will be permitted to update its Ancillary Service Schedule for self- arranged Ancillary Services until 1300 as detailed in Section 4.4.10. At 1330, ERCOT will procure, on behalf of the QSEs, any Ancillary Services not self-arranged.

4.4.9 ERCOT Notification of CSC Congestion and/or Capacity Insufficiency Based on 1100 Balanced Schedules

ERCOT will notify QSEs by 1115 of any CSC Congestion based on an evaluation of the QSE data supplied in the 1100 Balanced Schedules. ERCOT will also notify QSEs by 1115 of any capacity insufficiency, based on the difference between ERCOT's total Load forecast and the aggregate of QSE scheduled Load.

4.4.10 QSEs Submittal of Updated Balanced Energy Schedules

QSEs may submit an updated and revised Balanced Schedule at 1300 if ERCOT has issued Notification that there is either CSC Congestion or capacity insufficiency indicated by the Day Ahead Schedules at 1100. Schedules may not be updated unless ERCOT has issued such a Notification.

4.4.11 Ancillary Services Bid Submittal

(1) QSEs may submit, by 1300, Ancillary Service bids to ERCOT for any Ancillary Service market open during the Day Ahead Period. Submitted bids remain active for any period until:

(a) Selected by ERCOT; or

(b) Automatically expired by software at the time selected by the QSE.

(2) For Ancillary Service bid, a QSE must provide:

(a) The market for which the bid is being supplied;

(b) The period of time for which the bid is submitted;

(c) A dollars per megawatt price for the capacity bid;

(d) The quantity of capacity for which the bid price is effective;

(e) Any ties to other bids in other ERCOT Day Ahead Ancillary Service markets that may require those bids to be removed from those markets if a bid is selected by ERCOT in an earlier clearing market; and

(f) Expiration time of the bid.

[PRR496: Add item (g) to Section 4.4.11 upon system implementation:]

(g) For a Load Acting as a Resource bids for Responsive Reserve Service and Non-Spinning Reserve Service shall have the option to choose the bid to be awarded only as a complete block at the bid quantity. Bids requested in this fashion shall be defined as Block Bids. Block size will be limited to one hundred fifty (150) MWs for both RRS and NSRS.

(3) A Responsive Reserve capacity bid tied to a Regulation Up capacity bid may only exceed the Regulation Up capacity bid by X%, as approved by the ERCOT Board.

(4) A Non-Spinning Reserve capacity bid may only exceed Responsive Reserve capacity bid by X%, as approved by the ERCOT Board.

4.4.12 ERCOT Validation of QSE Day Ahead Schedules and Bids

At 1100 on the Day Ahead, ERCOT shall validate all of the data submitted by each of the QSEs in the Day Ahead Scheduling Process, as described in Section 4.7, Validation and Correction of Schedule Data, ERCOT will notify the affected QSEs of any invalid or mismatched schedules arising from the submitted data. ERCOT shall provide the QSEs with an opportunity to submit corrected information by 1115 if their schedules were either invalid or mismatched. Any remaining discrepancies or mismatches shall be adjusted by ERCOT as described in Section 4.7, Validation and Correction of Schedule Data.

If QSEs are allowed to submit updated Schedules, then at 1300 of the Day Ahead, ERCOT shall perform a final validation of the data submitted by the QSEs from the updated 1300 schedules. ERCOT will notify the affected QSEs of any invalid or mismatched schedules. ERCOT shall provide the QSEs with an opportunity to submit corrected information to ERCOT by 1315 if their schedules were either invalid or mismatched. Any remaining discrepancies or mismatches shall be adjusted by ERCOT as described in Section 4.7, Validation and Correction of Schedule Data.

ERCOT will validate that the amount of each capacity bid is within the limits defined in Section 4.4.11, Ancillary Services Bid Submittal. ERCOT will disregard all tied capacity bids, pursuant to Section 4.4.11 that do not adhere to the established limits.

4.4.13 ERCOT Day Ahead Ancillary Services Procurement Process

ERCOT will procure Regulation Up, Regulation Down, Responsive Reserves and Non-Spinning Reserves by 1330 in accordance with Section 6.6, Selection Methodology, to complete ERCOT's Day Ahead Ancillary Service Plan. ERCOT will review and then post on the MIS, the Market Clearing Prices for Capacity (MCPCs) for each Day Ahead Ancillary Service. These MCPCs may change due to subsequent purchases of AS during the Adjustment Period.

[PRR558: Replace Section 4.4.13 above with the following upon system implementation.]

ERCOT will procure Regulation Up, Regulation Down, Responsive Reserves and Non-Spinning Reserves by 1330 in accordance with Section 6.6, Selection Methodology, to complete ERCOT's Day Ahead Ancillary Service Plan. ERCOT will review and then post on the MIS, the Market Clearing Prices for Capacity (MCPCs) for each Day Ahead Ancillary Service. ERCOT will also post if the LaaR Responsive Reserve Service awards were prorated. These MCPCs may change due to subsequent purchases of AS during the Adjustment Period.

4.4.14 ERCOT Notification of Selected Ancillary Services Bids

By 1330, ERCOT will notify each QSE of the Ancillary Services procured from that QSE. At 1500, QSEs will provide an updated Day Ahead Ancillary Services schedule to ERCOT.

4.4.15 QSE Resource Plans

Each QSE that represents a Resource will present a Resource Plan to ERCOT at 1600. These Resources may be specific Generation Resources and/or Loads acting as Resources (LaaRs). The Resource Plan capacity should be sufficient to accommodate the combined quantity of energy and Ancillary Services scheduled by that QSE from the Resources that the QSE represents. The Resource Plan shall indicate the availability of the Resources represented by the QSE, including a lead-time status code, and the planned operating level of each Resource, for each hour of the Operating Day. The Resource Plan shall indicate the High Operating Limit (HOL) and Low Operating Limit (LOL), and High Sustainable Limit (HSL) and Low Sustainable Limit (LSL) by Resource. A Resource may be listed as unavailable to ERCOT if the Resource's capacity has been committed to markets in regions outside of ERCOT. ERCOT shall use other Resource Dispatch options to maintain system reliability prior to Dispatching a Generation Resource below its LOL. ERCOT shall request Qualifying Facilities (QFs), hydro units, and/or nuclear to operate below their LOLs only after other Resource Dispatch options have been exhausted.

ERCOT shall produce renewable production potential forecasts for Wind-powered Generation Resources (WGRs) to be used as the planned operating level in the Resource Plan during Replacement Reserve Service (RPRS) procurements. The WGR Production Potential (WGRPP) is an hourly eighty-percent (80%) probability of exceedance forecast of energy production for each WGR. ERCOT shall use a probabilistic Total ERCOT Wind Power Forecast (TEWPF) and select the forecast that the actual total ERCOT WGR production is expected to exceed eighty-percent (80%) of the time (eighty-percent (80%) probability of exceedance forecast). To produce the WGRPP, ERCOT will allocate the TEWPF eighty-percent (80%) probability of exceedance forecast to each WGR such that the sum of the individual WGRPP forecasts equal the TEWPF forecast. ERCOT shall produce these forecasts using information provided by WGRs to their QSEs including meteorological information or models, WGR power production curves and Supervisory Control and Data Acquisition (SCADA). ERCOT shall provide forecasts for each WGR to the QSEs representing WGRs and shall deliver the forecasts before

RPRS procurements to allow the QSEs to update the WGR Resource Plans. QSEs shall use the ERCOT-provided forecasts for WGRs as the planned operating level for the 1600 Resource Plan and prior to running an RPRS market in the Adjustment Period. The QSE may submit a lower operating level than the WGRPP forecast in the WGR Resource Plan if the WGR has communicated that it will be unavailable or operating at a reduced capability during an Operating Period which the forecast did not anticipate. QSEs representing only WGRs shall update their Resource Plans and schedules to reflect the expected wind-powered generation production after the close of the RPRS market. The energy schedules submitted by QSEs representing only WGRs should correspond with the Resource Plan scheduled energy output in order for Real Time balancing and the operator entered offset to perform properly. During Settlement Intervals in which QSEs representing only WGRs are using a Resource Plan modified due to insertion of the eighty-percent (80%) probability of exceedance forecast, ERCOT shall use the most recent available Resource Plan value prior to the ERCOT instruction to insert the eighty-percent (80%) probability of exceedance forecast.

QSEs shall use best efforts, consistent with Good Utility Practice, to continually update their Resource Plans to reflect the current and anticipated operating conditions of the Resources. ERCOT will monitor the performance of QSEs with respect to the submission of accurate Resource Plans in accordance with the measures established in Section 4.10, Resource Plan Performance Metrics. ERCOT will work with individual QSEs as necessary to improve the individual QSE performance.

4.4.16 ERCOT Receipt of Replacement Reserve Service Bids

QSEs may submit unit-specific Replacement Reserve Service (RPRS) bids to ERCOT by 1600. RPRS bids will have the following components:

(1) A dollar per megawatt capacity price at which the supplier will provide the service;

(2) A dollar per megawatt operational price;

(3) Designation of the specific Resource;

(4) Designation of the amount of capacity represented by the bid;

(5) The hours that the bid is effective; and

(6) An expiration time for the bid.

4.4.17 ERCOT Procurement of Replacement Reserve Service As Needed

ERCOT will purchase RPRS by 1800 based on bids submitted at 1600, ERCOT's most current Load forecast, and in accordance with Ancillary Services Section 6.6, Selection Methodology. ERCOT will notify QSEs of accepted RPRS bids by 1800. Insufficient RPRS bids will be addressed with OOMC.

4.4.18 Direct Current Tie Interconnection Day Ahead Scheduling Process

4.4.18.1 Control Area Operations

Control Area schedules between the ERCOT Control Area and interconnected non-ERCOT Control Area(s), through the use of schedules over Direct Current Tie(s), will be implemented in accordance with these Protocols, North American Electric Reliability Corporation (NERC) scheduling protocols, and in compliance with NERC operating policies. Scheduling must also be in accordance with any applicable Federal Energy Regulatory Commission tariffs.

ERCOT will perform schedule confirmation with the applicable interconnected non-ERCOT Control Area(s) and, if appropriate, will coordinate the approval process for the NERC tags as both the ERCOT Control Area and on behalf of ERCOT TSPs.

4.4.18.2 Linkage of Schedules with Interconnected Non-ERCOT Control Area Schedules

ERCOT will match the Supply and Obligation schedules submitted by the QSEs with interconnected non-ERCOT Control Area schedules obtained through the NERC Scheduling Process to confirm schedules and perform checkouts with adjacent interconnected non-ERCOT Control Areas. Entities submitting NERC tags for DC Tie schedules must identify the appropriate ERCOT QSE on the NERC tag. ERCOT will determine the linkage between interconnected non-ERCOT Control Area schedules and Supply and Obligation schedules submitted by QSEs. QSE schedules creating an ERCOT export across a DC Tie are an Obligation. QSE schedules creating an ERCOT import across a DC Tie are a Supply. If the interconnected non-ERCOT Control Area schedule exceeds the QSE schedule to or from the DC Tie, ERCOT will deny the interconnected non-ERCOT Control Area schedule with the applicable interconnected non-ERCOT Control Area(s). If any QSE's Supply or Obligation schedule indicated as being received or delivered to or from a DC Tie does not match the non-ERCOT Area schedule(s) as confirmed or linked by ERCOT, ERCOT shall settle those imbalances according to Section 6.8.1.13, Resource Imbalance and/or Section 6.9.5.2, Settlement For Balancing Energy for Load Imbalances.

4.4.18.3 Operation of DC Ties

ERCOT will confirm interconnected non-ERCOT Control Area schedule profiles with the DC Tie operator, who will control the tie to the schedules agreed to by both the designated Security Coordinator for the interconnected non-ERCOT Control Area and ERCOT.

4.4.18.4 Settlement

A QSE exporting from ERCOT through a DC Tie export schedule will include that DC Tie export schedule as an Obligation in its Balanced Schedule by using the identifier field indicating the appropriate DC Tie. Exports from ERCOT via DC Ties will be treated as a Load connected at transmission voltage in the settlement system and are responsible for allocated Ancillary Services, Transmission Losses, UFE, ERCOT administrative fees, as described in Section 9, Settlement and Billing, and any other applicable ERCOT fees.

The export schedules from the Public Service Company of Oklahoma, the Oklahoma Municipal Power Authority or the West Texas Utilities Company share of the Oklaunion Resource over the North DC Tie will not be treated as Load connected at transmission voltage, will not be subject to any of the fees described above, and will be limited to the actual net output of the Oklaunion Resource. ERCOT will record these schedules to support the billing of applicable TDSP tariffs.

Any QSE requesting the aforementioned "Oklaunion Exemption" is required to:

(1) Apply to ERCOT for the exemption;

(2) Establish a separate QSE (or sub-QSE) for the sole purpose of scheduling DC Tie exports for which the exemption would be applied; and

(3) Secure the Resources for a Balanced Schedule via a "bilateral" QSE transfer from the QSE(s) who actually represent the PGC(s) for Oklaunion.

With respect to the "Oklaunion Exemption," on a periodic basis ERCOT will verify that the sum of the "exempted" exports are not greater than the total output from the Oklaunion Resource at the Settlement Interval level.

A QSE importing into ERCOT through a DC Tie import schedule will include that DC Tie import schedule as a Supply in its Balanced Schedule by using the identifier field indicating the appropriate DC Tie. Imports into ERCOT via DC Ties will be treated as generation into the Congestion Zone in the settlement system.

Any changes in the interconnected non-ERCOT Control Area schedules due to a de-rating of the tie or other change within the NERC scheduling protocols will be communicated to ERCOT by the DC Tie Operator or designated security coordinator for the interconnected non-ERCOT Control Area. For any interconnected non-ERCOT Control Area schedules that are revised during the Operating Period, the DC Tie Operator shall communicate to the ERCOT the integrated schedule for the Settlement Intervals. If the DC Tie schedule flows as planned, then ERCOT will use schedules as the deemed meter readings for purposes of settlement. If the interconnected non-ERCOT Control Area schedule changes during the Operating Period, then ERCOT will use the changed interconnected non-ERCOT Control Area schedule as the deemed meter readings for purposes of settlement. ERCOT will not change the Supply or Obligation schedule of the QSE during the Operating Period.

4.4.18.5 Inadvertent Energy Account

Any difference between the scheduled net interchange and the actual net interchange at each DC Tie will be tracked in an Inadvertent Energy Account between ERCOT and each interconnected non-ERCOT Control Area. ERCOT will coordinate operation of the DC Tie(s) 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 interconnected non-ERCOT Control Areas will be in accordance with the NERC scheduling protocols and the Operating Guides.

4.4.19 Decision to Extend Day Ahead Scheduling Process to Two Day Ahead Scheduling Process

ERCOT will notify Market Participants, through the emergency Notification process, of system conditions as set out in Section 5, Dispatch, that require the Day Ahead Scheduling Process to be extended to two days ahead. During a period that Two Day Ahead schedules are required, all Scheduling Process requirements that apply to Day Ahead will similarly be applied to Two Day Ahead schedules, including ERCOT forecast of ERCOT System conditions and Load for the next two days, Balanced Schedules for the next two days, and Ancillary Services responsibility allocation for the next two days.

4.4.20 Publication of Resource Category Bid Limits

ERCOT will calculate and publish the Resource Category Generic bid limit for Balancing Energy Up and the Resource Category Generic bid limit for Balancing Energy Down for each Resource Category on each day for which the FIP is published, pursuant to Section 6.8.2.1, Resource Category Generic Costs, item (3).

(1) The Resource Category Generic bid limits for Balancing Energy Up for all gas-fired units will be calculated by multiplying the most recent FIP by the sum of a constant heat rate adder and the Resource Category heat rate, as used in the Resource Category Generic Fuel Cost calculation for upward instructions specified in Section 6.8.2.1, Resource Category Generic Costs.

(2) The Resource Category Generic bid limits for Balancing Energy Down for all gas-fired units will be calculated by multiplying the most recent FIP by the difference of a constant heat rate adder and the Resource Category heat rate, as used in the Resource Category Generic Fuel Cost calculation for downward instructions specified in Section 6.8.2.1, Resource Category Generic Costs.

(3) For all other Resource Categories, the Resource Category Generic bid limit for Balancing Energy Up and the Resource Category Generic bid limit for Balancing Energy Down will be calculated using the appropriate Resource Category Generic Fuel Cost calculation using the most recent FIP, if necessary, as specified in Section 6.8.2.1, Resource Category Generic Costs.

(4) The proposed value of the heat rate adder will be recommended by the appropriate TAC subcommittee and will be re-evaluated on a quarterly basis. The value of the heat rate adder must be approved by the ERCOT Board.

4.5 Adjustment Period Scheduling Process

4.5.1 Receipt of Adjustment Period Schedule Changes

During the Adjustment Period, QSEs may submit or change their energy schedules, and Ancillary Service schedules. Also during the Adjustment Period, QSEs may submit, change, or remove, Balancing Energy bids, or RPRS bids. Although a QSE is permitted to change an Ancillary Service schedule, it is not allowed to change the quantity of Ancillary Services awarded through the ERCOT procurement process. The QSE also may not change the amount of Self-Arranged AS from Day Ahead; however, the Resources supplying the Self-Arranged AS may be altered. If ERCOT calls on additional AS in the AP, the allocated portion of their additional AS may be Self-Arranged.

4.5.2 Receipt of QSE's Balancing Energy Bid Curves

ERCOT will receive QSEs Balancing Energy bid curves by the end of each Adjustment Period for an Operating Hour. QSEs may voluntarily submit Balancing Energy Service Up and Down bid curves to ERCOT for use in the Operating Period.

QSEs shall be required to submit mandatory Balancing Energy Service Up bid curves representing capacity reserved to supply the QSE's BES-Capable Non-Spinning Reserve Service (BESCNSRS) Obligation. QSEs shall be required to submit mandatory Balancing Energy Service Up bid curves representing capacity reserved to supply the QSE's On-line BESCNSRS obligation in accordance with paragraph (3) of Section 6.5.5, Non-Spinning Reserve Service (NSRS). The QSE's Balancing Energy Service Up bids required by BESCNSRS shall be no lower than FIP*18 MMBtu/MWh. If any portion of a Resource is providing BESCNSRS, the entirety of Balancing Energy Service Up offers from that Resource must be no lower than FIP*18 MMBtu/MWh.

QSEs shall be required to submit mandatory Balancing Energy Service Down bid curves. The QSEs will submit Balancing Energy Service Down bids based on the specifications set forth below.

(1) For each Congestion Zone, the minimum bid shall be the lesser of the following:

(a) ERCOT's required percentage of Balancing Energy Service Down bids as posted at 0600 of the Day Ahead multiplied by the QSE's net energy schedule for Balancing Energy Service requirements.

(b) The QSE's net energy schedule for Balancing Energy Service requirements less the QSE's minimum sustainable capacity (except for Out of Merit Capacity (OOMC) units, Reliability Must-Run (RMR) Units, and Generation Resources undergoing required testing as defined in Protocols and Operating Guides) represented in its Resource Plan.

$$MinimumDownBalanceBidByZone =$$
$$Min\left((NetEneSch * DBES\,\mathrm{Re}\,q\%), (NetEneSch - \sum_{u} OLMinCap) \right)$$

(2) If the sum of the Balancing Energy Service Down bids for each Congestion Zone from paragraph (1) above is more than the QSE's net energy schedule for Balancing Energy Service requirements less the QSE's minimum sustainable capacity (except for OOMC units, RMR Units, and Generation Resources undergoing required testing as defined in Protocols and Operating Guides) represented in its Resource Plan, and less the QSE's scheduled Regulation Service Down (RGSD), then this amount shall be the minimum ERCOT-wide Balancing Energy Service requirement. In this case, no zonal requirement shall exist as the requirement will be ERCOT-wide.

$$MinimumDow\ \ nBalanceBi\ \ dERCOTWide\ \ =$$
$$Max\left[0, \sum_{z} NetEneSch\ - \sum_{u} OLMinCap\ - Sch\ \mathrm{Re}\ gDn \right]$$

The net energy schedule for Balancing Energy Service requirements is the QSE's scheduled energy per Congestion Management zone less any QSE trades, energy scheduled by ERCOT from Resources under an RMR Agreement, energy scheduled from Resources that received an OOMC Dispatch Instruction for the hour, and energy scheduled from Generation Resources undergoing required testing as defined in Protocols and Operating Guides.

Where:

NetEneSch =	the QSE's scheduled energy per Congestion Management zone less any QSE trades, energy scheduled by ERCOT from Resources under an RMR Agreement, energy scheduled from Resources that received an OOMC Dispatch Instruction for the hour, and energy scheduled from Generation Resources undergoing required testing.
OLMinCap =	Low Sustainable Limit (LSL) for each On-line and available unit (except for RMR Units, OOMC units, and Generation Resources undergoing required testing).
SchRegDn =	RGSD scheduled by the QSE
DBESReq% =	Balancing Energy Service Down percentage posted by ERCOT
Z=	Congestion Management zone
u =	unit

Balancing bid curves will have the following components:

(a) $/MWh

(b) Quantity (MW)

(c) Congestion Zone

(d) Ramp rate

(3) The specified ramp rate may not be less than the Market Participant minimum required Balancing Energy Service Down bid divided by forty (40). The calculated minimum required Balancing Energy Service Down bid amount must be deployable within one (1) hour.

[PRR675: Replace the above language with the following upon system implementation:]

Balancing bid curves will have the following components:

(a) $/MWh

(b) Quantity (MW)

(c) Congestion Zone

(d) Ramp rate or ramp rate curve

(3) QSEs may submit a portfolio ramp rate curve with multiple points for Up and Down Balancing Energy Service. This will be used by ERCOT in clearing the Up and Down Balancing Energy Service market.

(4) The specified ramp rate may not be less than the Market Participant minimum required Balancing Energy Service Down bid divided by forty (40). The calculated minimum required Balancing Energy Service Down bid amount must be deployable within one (1) hour.

[PIP 210: When block deployment for Loads acting as a Resource can be implemented, add the following paragraph:]

A Load acting as Resource (LaaR) has the option to request a Load bid to be deployed only as a complete block. The block deployment option shall be selected at the time of bid submittal.

4.5.3 ERCOT Receipt of Resource Specific Premiums for Operational Congestion Management

QSEs may submit hourly Resource specific premiums for Operational Congestion Management to ERCOT by 1600. Resource specific premiums will have the following components:

(1) A dollar per megawatt hour ($/MWh) price premium at which the supplier will accept an instruction to increase its level of operation from its current operating point;

(2) A dollar per megawatt hour ($/MWh) price premium at which the supplier will accept an instruction to decrease its level of operation from its current operating point;

(3) Unit ramp rate; and

(4) Designation of the specific Resource.

4.5.4 ERCOT Validation of Schedule Changes

ERCOT will validate all Adjustment Period Schedules in accordance with Section 4.7, Validation and Correction of Schedule Data.

4.5.5 ERCOT Evaluation of System Security and Adequacy

As required throughout the Adjustment Period, ERCOT will evaluate Ancillary Service requirements, Local Congestion, Zonal Congestion, and capacity insufficiency using the Operational Model, based on updated QSE schedules, Resource Plans and the current ERCOT Load forecast.

ERCOT will determine the level of Resources available to meet reliability needs based on the Resource Plan. ERCOT will consider the On-line generation; neither scheduled nor bid as Balancing Energy, as a possible source of additional Balancing Energy bids.

4.5.6 ERCOT Notice of Need to Procure Replacement Reserve Service Resources

During the Adjustment Period, after the evaluation referenced in Section 4.5.5, ERCOT Evaluation of System Security and Adequacy, ERCOT may announce the need to procure RPRS in accordance with Section 6.6.3.2.1, Specific Procurement Process Requirements for Replacement Reserve Service in the Adjustment Period. Following an ERCOT Notice of the need to procure any additional Ancillary Services, QSEs may adjust their energy schedules in accordance with Section 4.5.1, Receipt of Adjustment Period Schedule Changes.

The typical RPRS procurement process will follow the following timeline with time X being the start of a clock hour when ERCOT identifies Zonal and Local Congestion, or capacity insufficiency. Time X can be the start of any clock hour during the Adjustment Period but cannot be less than two (2) hours prior to the Operating Hour that energy from the RPRS unit is required.

RPRS Procurement Process	**QSE Responsibility:**	**ERCOT Responsibility:**
Time X		• Identify need for additional RPRS. • Notify market of intent to purchase RPRS at time X+60 minutes.

RPRS Procurement Process	QSE Responsibility:	ERCOT Responsibility:
Time X plus 30 minutes	• QSEs have the opportunity to update their Balanced Schedules.	• Review updated Balanced Schedules. • Validate schedules and notify affected Qualified Scheduling Entities (QSEs) of any invalid or mismatched schedules.
Time X plus 45 minutes	• Resubmit corrected schedules.	• Re-evaluate the need for RPRS based on the updated AP schedules.
Time X plus 60 minutes		• Purchase needed RPRS using bids received at time X.

4.5.7 Available Bids for RPRS

QSEs may submit, change, or delete RPRS bids throughout the Adjustment Period. If ERCOT notifies Market Participants that RPRS is needed, only bids that were submitted before the Notice are eligible. Once the Notice is given, no further bids are eligible for that procurement cycle.

4.5.8 ERCOT Notice of Need to Procure Additional Ancillary Services

During the Adjustment Period, after the evaluation referenced in Section 4.5.5, ERCOT Evaluation of System Security and Adequacy, ERCOT may announce the need to procure additional Ancillary Services in accordance with Section 6.6.3.2, ERCOT Ancillary Services Procurement during Adjustment Period.

The Adjustment Period AS procurement process for RRS, NSRS and RGS will use the following timeline with time X being the start of a clock hour when ERCOT identifies the need for additional AS. Time X can be the start of any clock hour during the Adjustment Period but cannot be less than three (3) hours prior to the start of the Operating Hour that the additional AS capacity is required.

Additional AS Procurement Process	QSE Responsibility:	ERCOT Responsibility:
Time X (Not later than Operating Hour start minus 180 minutes)		• Identify need for additional RRS, NSRS and/or RGS. • Notify market by voice communication of intent to purchase RRS, NSRS, and/or RGS at time X+90 minutes. This verbal communication will include the total amount of additional AS capacity required.
Time X plus 60 minutes (Not later than	• QSEs may update Ancillary Service bids consistent with Section 4.5.9.1.	• Allocate additional AS responsibility to LSEs and aggregate to the QSE level.

Operating Hour start minus 120 minutes).		
Time X plus 75 minutes (Not later than Operating Hour start minus 105 minutes	• QSEs may update their Balanced Schedules, including additional Self-Arranged AS.	• Review updated Balanced Schedules. • Validate schedules and notify affected Qualified Scheduling Entities (QSEs) of any invalid or mismatched schedules.
Time X plus 90 minutes (Not later than Operating Hour start minus 90 minutes)		• Purchase needed RRS, NSRS, and/or RGS using bids received at time X.
Time X plus 120 minutes (Not later than Operating Hour start minus 60 minutes)	• Resubmit schedules to include awards.	

4.5.9 Available Bids for Ancillary Services in the Adjustment Period

QSEs may submit, change, or delete Ancillary Services bids throughout the Adjustment Period.

4.5.9.1 Resubmittal of Bids for Ancillary Services in the Adjustment Period

If a QSE resubmits a bid for an Ancillary Service that it submitted in a previous market for the same Ancillary Service, but was not selected, the resubmitted bid must meet the following criteria to be considered a valid bid in the subsequent market:

(1) The bid quantity may not be less than the quantity of the bid from the previous market, unless that QSE has not resubmitted any of the higher priced bids that were not selected in the previous market; and

(2) The bid must be priced equal to or less than the price of the bid not selected from the previous market.

4.5.9.2 Submittal of New Bids for Ancillary Services in the Adjustment Period

If an individual QSE submits Ancillary Services bids in the Adjustment Period that, in total, are greater in quantity than that QSE's total quantity of bids that were not selected in a previous market, the incremental amount of Ancillary Services bid may be submitted at any price.

QSEs may change or delete any bids submitted or resubmitted during the Adjustment Period, subject to the restrictions of Protocols Section 4.5.9.1, Resubmittal of Bids for Ancillary Services in the Adjustment Period.

4.5.10 Updated Resource Plans

QSEs shall update their Resource Plans to ERCOT to reflect Resource status changes.

4.5.11 Scheduling Requirements for RMR Units and Black Start Resources

4.5.11.1 Day Ahead Scheduling for RMR Units and Black Start Resources

Below is a Day Ahead Scheduling Process for RMR Units and Black Start Resources:

RMR Scheduling	**QSE Responsibility:**	**ERCOT Responsibility:**
0600	Submit initial unit Availability Plan for RMR and/or Synchronous Condenser Units and Black Start Resources.	
0900		Provide initial Delivery Plan to QSEs representing RMR and/or Synchronous Condenser Units.
1830		Provide updated Delivery Plan to QSEs representing RMR and/or Synchronous Condenser Units.

4.5.11.2 RMR Unit, Synchronous Condenser Unit, and Black Start Resource Availability Plan

In addition to updating the Resource Plan, QSEs representing RMR Units, Synchronous Condenser Units, and Black Start Resources shall submit initial Availability Plans for those Resources by 0600 in the Day Ahead Period.

QSEs representing RMR Units, Synchronous Condenser Units, and Black Start Resources shall submit revised Availability Plans reflecting changes in the plans as soon as reasonably practicable, but in no event later than sixty (60) minutes after the event that caused the change.

4.5.11.3 ERCOT RMR Units and Synchronous Condenser Units Delivery Plan

By 0900, ERCOT shall notify the QSE representing a RMR Unit and/or a Synchronous Condenser Unit of the initial Delivery Plan for any unit that is required for reliability. At any time during the Day Ahead or Adjustment Period, ERCOT may notify the QSE representing a RMR Unit and/or a Synchronous Condenser Unit, of any modifications to the Delivery Plan for the RMR Unit or the Synchronous Condenser Unit. At 1830, ERCOT may update its Delivery Plan to include any RMR and/or a Synchronous Condenser Unit that is necessary to maintain reliability of the system, based on the Replacement Reserve Service procurement process.

[PRR428: Add the following to Section 4.5.11.3 upon system implementation.]

4.5.11.3.1 Static Scheduling of Energy from RMR Resources

As soon as practical after being provided the Delivery Plan, the QSE shall update its Resource Plan and Balanced Schedule with ERCOT to reflect energy being scheduled from RMR Units. The Supply in the indicative schedule shall include energy scheduled from RMR Units by Congestion Zone and the Obligation in the indicative schedule shall include a QSE to ERCOT schedule by Congestion Zone.

4.5.11.3.2 Responsibility Transfer Scheduling of Energy from RMR Resources

As soon as practical after being provided the Delivery Plan, the QSE shall update its Resource Plan and Balanced Schedule with ERCOT to provide an indicative schedule reflecting energy being scheduled from RMR Units. The Supply in the indicative schedule shall include energy scheduled from RMR Units by Congestion Zone and the Obligation in the indicative schedule shall include a QSE to ERCOT schedule by Congestion Zone. These indicative schedules shall be offset with the Controlling Entity's Real Time signal provided under the Responsibility Transfer outlined in Section 4.9.4.3, Principles for Responsibility Transfers For RMR Units.

4.5.11.4 Receipt of QSE's Balancing Energy Up Bid Curves for RMR Units

ERCOT will receive RMR Balancing Energy Up bid curves from a QSE, or a subdivision thereof that represents only RMR Units. QSEs, representing RMR Units, may voluntarily submit Balancing Energy Service Up to ERCOT for use in the Operating Period; provided, however:

(1) Balancing Energy Up bid curves from RMR Units must be independent of the QSE's other Balancing Energy bid curves.

(2) Balancing Energy Up bids from RMR Units are limited to any undeployed capacity of the RMR Unit and may only be submitted if the RMR Unit has first been deployed by ERCOT.

4.5.11.4.1 Balancing Bid Curve Contents

Balancing bid curves will have the following components:

(1) $/MWh;

(2) Quantity (MW);

PUBLIC

(3) Congestion Zone; and

(4) Ramp Rate.

4.6 Operating Period Process

The Operating Hour will begin one hour after the close of each Adjustment Period. The Operating Period is defined as the Operating Hour and the preceding clock hour. During the Operating Period, ERCOT shall:

(1) Deploy Balancing Energy as described in Section 6.7.1, Deployment of Balancing Energy;

(2) Make use of Ancillary Services as needed;

(3) Incorporate Dynamic Schedules into the Dispatch process;

(4) Operate the ERCOT System in accordance with Section 5, Dispatch and Section 6, Ancillary Services; and

(5) Publish the MCPE immediately after the deployment of Balancing Energy for the upcoming Settlement Interval.

4.7 Validation and Correction of Schedule Data

4.7.1 Overview of Validation and Correction Process

ERCOT will review and validate QSE-submitted schedule data. For purposes of this section, validation shall mean ensuring that:

(1) Schedules submitted to ERCOT are balanced;

(2) Schedules match;

(3) A QSE does not schedule for Market Participants it does not represent;

(4) The quantity of Self-Arranged Ancillary Services in the schedule does not exceed limits (as described in these Protocols) based on schedules submitted;

(5) The quantity of ERCOT-provided Ancillary Services for each service type specified in the QSE's schedule may not be greater than the QSE's total Ancillary Service Obligation, including both ERCOT allocated Ancillary Service Obligations and Obligations scheduled to other QSEs through QSE to QSE Ancillary Service schedules, for each service type;

(6) Awarded bids in the ERCOT Ancillary Service procurement process are included in QSE Ancillary Service schedules; and

(7) Other checks as necessary to ensure compliance with these Protocols.

4.7.2 Schedule Validation Process

(1) ERCOT will only accept Balanced Schedules.

(2) ERCOT will check to ensure Inter-QSE Trades match. If ERCOT identifies mismatched Inter-QSE Trades, ERCOT shall use the following process to remedy mismatches:

(a) If ERCOT detects a mismatch in the scheduled quantities or Congestion Zone designation for an Inter-QSE Trade for energy, ERCOT shall promptly notify both the receiving QSE and sending QSE that a mismatch exists and shall allow them fifteen (15) minutes to resolve the mismatch and submit modified schedules.

(b) If mismatched Inter-QSE Trades are not resolved in the allotted time, then ERCOT shall consider any amount of a mismatched Inter-QSE energy schedule submitted by a QSE as a Resource which exceeds the corresponding Inter-QSE energy schedule submitted by a QSE as a Load as a "mismatched amount delivered to ERCOT." ERCOT shall also consider any amount of a mismatched inter-QSE energy schedule submitted by a QSE as a Load which exceeds the corresponding Inter-QSE energy schedule submitted by a QSE as a Resource as a "mismatched amount received from ERCOT." ERCOT will use these amounts to settle with each offending QSE as specified in Section 6.9.8, Settlement for Mismatched Inter-QSE Energy Schedules. Additionally, ERCOT will charge a mismatched schedule-processing fee for providing this service.

[PRR666: Replace Section 4.7.2(b), with the following upon system implementation:]

(b) If mismatched Inter-QSE Trades are not resolved in the allotted time, then ERCOT shall consider any amount of a mismatched Inter-QSE energy schedule submitted by a QSE as a Resource which exceeds the corresponding Inter-QSE energy schedule submitted by a QSE as a Load as a "mismatched amount delivered to ERCOT." ERCOT shall also consider any amount of a mismatched inter-QSE energy schedule submitted by a QSE as a Load which exceeds the corresponding Inter-QSE energy schedule submitted by a QSE as a Resource as a "mismatched amount received from ERCOT." ERCOT will use these amounts to settle with each offending QSE as specified in Section 6.9.8, Settlement for Mismatched Inter-QSE Energy Schedules, and Section 6.9.2.1, Settlement for RPRS Procured for System-wide Capacity Insufficiency. Additionally, ERCOT will charge a mismatched schedule-processing fee for providing this service.

(c) ERCOT shall notify both QSEs involved in a mismatched Inter-QSE Trade, as described in Section 4.7.2(2)(b), of the Entities involved in the mismatch as well as the existence and amount of the mismatch.

(3) Inter-QSE Ancillary Services Trade Mismatches: ERCOT shall follow the following process to remedy mismatches in Inter-QSE Trades of Ancillary Services:

(a) If ERCOT detects a mismatch in the Ancillary Service type, scheduled quantities or locations for an Inter-QSE Trade of Ancillary Services, ERCOT shall promptly notify both the receiving QSE and sending QSE that a mismatch exists and shall allow them fifteen (15) minutes to resolve the mismatch and to submit modified Schedules.

(b) If the QSEs are unable to resolve the mismatch in the allotted time, ERCOT shall adjust the QSEs' schedules to meet the Ancillary Service Plan. The adjustment to the schedules will match the Resource. Any Ancillary Service schedule deficit that results from a mismatch will be filled by the Ancillary Service market.

(c) If QSEs are unable to resolve a mismatch during the Day Ahead period, ERCOT will purchase any deficient Ancillary Service in the Day Ahead Ancillary Service market on behalf of those QSEs as required.

(d) If QSEs are unable to resolve a mismatch in the allotted time during the Adjustment Period, ERCOT shall adjust the QSEs' Schedules to meet the Ancillary Service Plan as described above and will declare a default on any deficient providers as described in Section 6.6.3.2, ERCOT Ancillary Services Procurement During Adjustment Period.

(e) ERCOT shall notify each QSE whose Schedule has been adjusted as to the adjustment in its Schedule.

4.7.3 Availability of ERCOT Data Validation Rules and Software

ERCOT shall make copies of its validation rules and any nonproprietary or non-confidential software available to the QSEs, enabling QSEs to pre-validate their data.

4.8 Temporary Deviations from Scheduling Procedures

If ERCOT is unable to comply with any of the deadlines in Sections 4.4, Day Ahead Scheduling Process, or Section 4.5, Adjustment Period Scheduling Process, it may temporarily deviate from those timing requirements to the extent necessary to ensure the secure operation of the ERCOT System. Temporary measures may include varying the timing requirements as specified in Section 4.4.19, Decision to Extend Day Ahead Scheduling Process to Two Day Ahead Scheduling Process, or omitting one or more procedures in the Scheduling Process. In such an event, ERCOT shall immediately declare an Emergency Condition and notify all QSEs of the following:

(1) Details of the affected timing requirements and procedures;

(2) Details of any interim requirements;

(3) An estimate of the period for which the interim requirements will apply; and

(4) Reasons for the temporary variation.

If, despite the variation of any time requirement or the omission of any procedure, ERCOT is unable to operate the Day Ahead Scheduling Process, ERCOT may abort the Day Ahead Scheduling Process and require all schedules to be submitted in the Adjustment Period.

If, despite the variation of any time requirement or omission of any step, ERCOT is unable to operate the Adjustment Period Scheduling Process, ERCOT may abort the Adjustment Period process and operate under its Operating Period procedures.

If ERCOT implements a Two Day Ahead Scheduling Process, that process shall be as described in Section 4.4.19, Decision to Extend Day Ahead Scheduling Process to Two Day Ahead Scheduling Process.

4.9 Dynamic Schedules

4.9.1 Dynamic Load Schedules

QSE's may use dynamic power signals to control generation to match a metered Load in order to minimize the QSE's exposure to the Balancing Energy market. To implement the Dynamic Schedule the QSE will send Real Time telemetry to ERCOT that is equal to the metered Load, which the QSE wishes to follow. ERCOT will integrate the signal for each Settlement Interval and provide the integrated signal to settlement as the scheduled Obligation for that metered Load. Settlement will use this integrated value as a scheduled Supply for that interval for the QSE. At settlement the integrated values will be used as a Supply or Obligation schedule.

The QSE's schedule will include one Supply Resource (or fleet) designated to follow the Dynamic Schedule for a Load. The designated Supply schedule will be estimated in the same manner as the designated Load. At settlement, the estimated schedule for the designated Resource will be replaced with the integrated final power signal from the dynamic Load.

4.9.2 Approval of the Use of Dynamic Load Schedules

(1) Each QSE desiring to use Dynamic Load Schedules must submit a proposal of the Dynamic Schedule to ERCOT for analysis of Congestion impacts and reliability in accordance with the Operating Guides.

(2) Subject to number (1) above, any QSE representing Non Opt-In Entities that own, had under construction, or had contractual rights to Generation Resources, as of May 1, 2000,

may use Dynamic Schedules. Once a Non Opt-In Entity (NOIE) offers Customer Choice, it must submit a new proposal for Dynamic Load Scheduling to ERCOT.

(3) ERCOT will approve dynamic scheduling proposals on a case-by-case basis. Approval will be based on the schedule's impact on ERCOT's ability to determine and manage Congestion, ERCOT's ability to monitor Generation Resource and Load behavior associated with the schedule and the schedule's impact on system reliability. QSEs representing Non-Opt In Entities, which submit proposals in accordance with (1) and (2) above will be accepted by ERCOT.

(4) New proposals for Dynamic Load Schedules within Congestion Zones will be considered after June 1, 2001 and across Congestion Zones after June 1, 2002.

4.9.3 Principles for Dynamic Schedules

(1) All power signals for Dynamic Schedules must be sent to ERCOT in Real Time via telemetry.

(2) Each Dynamic Load Schedule must be tied to 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 T&D Losses. A Load or group of Loads that is/are dynamically scheduled can only be followed by Generation Resources represented by the same QSE as the Load.

(3) Each Dynamic Load Schedule will indicate the dynamic power signal that will be used to create the final schedule.

(4) Dynamic Load Schedules tied to Load meters (or groups of Load meters) may be used between Congestion Zones.

(5) A QSE using Dynamic Load Schedules shall send a dynamic power signal or signals to ERCOT.

(6) Each QSE with a Dynamic Load Schedule will include in its schedules and plans submitted to ERCOT, an estimate for the integration of the schedule for each Settlement Interval. These schedule integration estimates will be used for allocation of RPRS costs.

(7) ERCOT will integrate the dynamic power signal sent by a QSE for each Settlement Interval. This integrated signal shall replace the estimate and will be used in settlement as the final schedule. Dynamic Schedules do not alter the settlement process for metered Loads.

(8) If a signal is lost for any reason, ERCOT will use the final schedule for Settlement purposes.

(9) ERCOT will use the dynamic power signal in each of the applicable QSE's SCE equation.

4.9.4 Responsibility Transfers (RspT)

4.9.4.1 Approval of the Use of Responsibility Transfers

(1) Intra-zonal Responsibility Transfers (RspTs) will be approved unless ERCOT determines it cannot accommodate these transfers without compromising reliability or settlement accuracy.

(2) Each QSE that proposes to use an RspT must submit a proposal of the RspT to ERCOT for analysis of Congestion impacts and reliability in accordance with the Operating Guides. The proposal for each RspT shall identify:

(a) Controlling Entity;

(b) Following Entity;

(c) Congestion Zone;

(d) Maximum value;

(e) Units supplying energy; and

(f) Other information required by ERCOT.

4.9.4.2 Principles for Responsibility Transfers

(1) RspT may be used to shift responsibility for Supply of a defined maximum amount of MWs from one QSE to another QSE within the same Congestion Zone after the close of the Adjustment Period. As the RspT changes the responsibility for Supply of one QSE there must be an equal and opposite change in the responsibility for Supply of the other QSE.

(2) One of the QSEs will act as the controller of the Real Time Dynamic signal. That Controlling Entity (CE) will send a Real Time power signal to ERCOT representing that QSE's power commitment to the other QSE, the Following Entity (FE).

(3) ERCOT will use the dynamic power signal from the CE in its calculation of the CE's SCE. ERCOT will also use the dynamic power signal from the CE to calculate an equal and opposite value to use in calculation of the FE's SCE. The FE will use a signal from the CE to calculate its (the FE's) SCE.

(4) ERCOT will integrate the dynamic power signal from the CE for each Settlement Interval and use this value as an offset in the CE's settlement for Resource imbalance. An equal but opposite offset will be used in the FE's settlement for Resource imbalance.

(5) If the signal from the CE is lost, ERCOT will use the last good value received from the CE until the CE manually replaces the value, or the signal is restored.

[PRR428: Add Section 4.9.4.3 upon system implementation]

4.9.4.3 Principles for Responsibility Transfers For RMR Units

(1) RspT may be used to schedule energy from an RMR Resource's QSE to ERCOT.

(2) The RMR Resource's QSE will act as the controller of the Real Time Dynamic signal. The QSE will send a Real Time power signal to ERCOT representing the amount of RMR energy being delivered from RMR Resources to ERCOT by Congestion Zone. The dynamic signal will be consistent with and will not exceed the RMR deployment instructions from the final Delivery Plan and/or subsequent Adjustment Period changes, and the operation and availability of the RMR Resources.

(3) ERCOT will use the dynamic power signal from the RMR QSE in its calculation of the RMR QSE's SCE.

(4) ERCOT will integrate the dynamic power signal from the RMR QSE for each Settlement Interval and use this value as an offset in the RMR QSE's settlement for Resource imbalance.

(5) If the signal from the Controlling Entity (CE) is lost, ERCOT will use the last good value received from the CE until the CE manually replaces the value, or the signal is restored.

4.9.5 Responsibility Transfer for Balancing Energy Bidding

Certain PUCT mandated Capacity Auction Products (as defined in PUCT S.R. §25.381) allow the entitlement holder (Buyer) to provide Balancing Energy Service to ERCOT whenever a Responsibility Transfer ("RspT") between Buyer and Seller's respective QSEs is established. The procedure for providing Balancing Energy from Capacity Auction Products is set forth in Protocols Section 6.5.2.1, Balancing Energy Service Bids from Bilateral Contracts.

4.10 Resource Plan Performance Metrics

4.10.1 Introduction and Calculation of QSE Scores

ERCOT shall measure the performance of QSEs submitting status of specific Generation Resources and/or LaaRs through the Resource Plan (Section 4.4.15, QSE Resource Plans), according to the requirements of this section. ERCOT shall identify and contact those QSEs that continually fail to comply with the Resource Plan Performance Metrics described in this Section.

The Resource Plan performance metrics measures (QSE Measure Score) defined in this Section will be applied to all QSEs representing Resources that are required to be included in their Resource Plans. ERCOT shall collect and apply the pertinent data from the proper ERCOT systems to perform these measurements. These performance metrics shall be measured as precisely and efficiently as possible, consistent with the performance requirements defined in the Protocols.

ERCOT shall generate QSE Measure Scores as follows:

$$\text{QSE Measure Score} = 1 - \left(\frac{\text{\# of Occurrences}}{\text{Total \# of Monthly Samples}} \right)$$

Where:

Number of Occurrences	Instances of failure to meet the measurement criteria, as defined in Section 4.10.3, Resource Status Measure through Section 4.10.8, Total Up AS Scheduled Obligation Measure
Number of Monthly Samples	As defined in Section 4.10.3, Resource Status Measure through Section 4.10.8, Total Up AS Scheduled Obligation Measure

4.10.2 Scoring Review

ERCOT shall calculate a QSE Measure Score for each Resource Plan Performance Metric on a monthly basis. Scores equal to or greater than ninety percent (90%) will be considered to be in compliance with Resource Plan accuracy requirements. ERCOT shall initiate a review process with the QSE for any measure set forth in Sections 4.10.3, Resource Status Measure through 4.10.8, Total Up AS Scheduled Obligation Measure where the QSE's Measure Score is less than ninety percent (90%). Scores that remain below ninety percent (90%) for a measure for more than three (3) consecutive months shall be considered to have failed to pass that measure.

4.10.3 Resource Status Measure

The "Resource Status Measure" compares the Resource Plan status to the Resource telemetered status using the last Resource Plan submitted by the QSE before the start of the Operating Hour but after the end of the Adjustment Period. ERCOT-approved Aggregated Units are treated as single units for the purposes of calculating the score for this measure. Only Resources that are required to provide telemetry to ERCOT through their QSE are included in this measure. LaaRs, Generation Resources undergoing required testing, and Renewable Resources pursuant to item (1) of Section 6.8.2.1, Resource Category Generic Costs, are excluded from this measure.

The hourly Resource Plan status for a particular Generation Resource is compared to the corresponding real power telemetry values delivered to ERCOT's Supervisory Control And Data Acquisition (SCADA) by the QSE for the same Resource. To calculate the score for the Resource Status Measure, the real power telemetry values are averaged into five (5) minute intervals creating twelve (12) interval values in an hour. The maximum and minimum interval values are used to determine whether an Occurrence is recorded for that Resource. An Occurrence is recorded for a particular Generation Resource if the Resource Plan status is Off-line and the minimum interval value is greater than one-half (0.5) MW for the same Resource in a given hour. An Occurrence is also recorded for a particular Generation Resource if the Resource Plan status is On-line, the Resource Plan planned operating level is greater than zero (0) MW, and the maximum interval value is less than one-half (0.5) MW for the same Resource in a given hour. Only one (1) Occurrence can be recorded per Resource per hour.

To determine the QSE Measure Score for the Resource Status Measure, Occurrences are summed for all Resources for every hour in a given month and divided by the total number of entries submitted in the Resource Plan by a QSE for all Resources when corresponding real power telemetry values exist for those Resources for that month.

The two (2) hours immediately following a Forced Outage of a Generation Resource will be excluded in the calculation of this measure.

4.10.4 Resource Low Sustainable Limit as a Percent of High Sustainable Limit Measure

The "Resource LSL as a percent of HSL Measure" compares the range between the Low Sustainable Limit (LSL) and High Sustainable Limit (HSL) submitted in the Resource Plan using the last Resource Plan submitted by the QSE before the start of or during the Operating Hour but after the end of the Adjustment Period. Only 15-minute intervals when the Resource Plan HSL of a Resource is greater than zero (0) MW and the Resource Plan status for the same Resource is On-line are included in the calculation of this measure. ERCOT-approved Aggregated Units are treated as single units for the purposes of calculating the score for this measure. LaaRs, Generation Resources undergoing required testing, and Generation Resources with a Resource Category Generic Fuel Cost of "Renewable" (excluding Wind-powered Generation Resources (WGRs)) or "Hydro" pursuant to item (1) of Section 6.8.2.1, Resource Category Generic Costs, are excluded from this measure.

To determine whether an Occurrence is recorded, the Resource Plan HSL is multiplied by the percentage corresponding to the Resource category as specified in item (1) of Section 6.8.2.1, for a particular Resource. The Resource Plan LSL should not exceed the percentage of the Resource Plan HSL in the table below for a given Generation Resource; such an exceedance shall be recorded as an Occurrence. The Resource category for each Resource is based on the Resource category designated by the Resource Entity for the Resource.

Resource Category Generic Fuel Cost	**LSL Percent of HSL**
Qualifying Facilities	As approved by ERCOT
Nuclear	70
Hydro	N/A
Coal and Lignite	60
Combined Cycle greater than 90 MW	85
Combined Cycle less than or equal to 90 MW	85
Gas Steam Supercritical Boiler	40
Gas Steam Reheat Boiler	40
Gas Steam Non-reheat or boiler without air-preheater	40
Simple Cycle greater than 90 MW	90

Simple Cycle less than or equal to 90 MW	90
Diesel (and all other diesel or gas-fired Resources)	90
Renewable (excluding WGR and Hydro renewable Resources)	N/A
WGR	As described in Section 4.10.4.1, LSL Requirement for WGRs
Block Load Transfer	N/A

If the Resource Plan LSL is greater than the resulting value, then an Occurrence is recorded for that Resource for that interval. Only one (1) Occurrence can be recorded per Resource per interval. To determine the QSE Measure Score for the Resource LSL as a percent of HSL measure, Occurrences are summed for all Resources for every interval in a given month, and divided by the total number of entries submitted in the Resource Plan by a QSE for all Resources where the HSL is greater than zero (0) MW and the Resource Plan Status is On-line for every interval in that month.

Generation Resources may request (with appropriate supporting documentation) an alternate percentage, subject to approval by ERCOT.

QSEs may request, with appropriate supporting documentation, an exclusion from this measure for any Generation Resource the QSE represents, subject to approval by ERCOT, where the LSL was increased or the HSL was decreased due to limiting technology or physical and/or mechanical issues with the Generation Resource for which the exclusion is being requested.

4.10.4.1 LSL Requirement for WGRs

For WGRs, the LSL for the "Resource LSL as a percent of HSL Measure" shall be ten-percent (10%) of the name plate rating, as registered with ERCOT. WGRs with in-service dates before January 1, 2003 are excluded from this measure.

4.10.5 Day Ahead Zonal Schedule Measure

The "Day Ahead Zonal Schedule Measure" compares each QSE's zonal energy schedule to the QSE's aggregated planned operating level for that Congestion Zone at the time a Day Ahead Schedule validation, as described in Section 4.7, Validation and Correction of Schedule Data, is run and approved. The QSE's zonal energy schedule and the aggregated planned operating level for that Congestion Zone for all twenty-four (24) hours of the next day are recorded at the time of the Day Ahead Schedule validation. The QSE's zonal energy schedules for each fifteen (15)-minute interval in an hour are averaged over the entire hour to create the QSE's average zonal energy schedule. The planned operating level for all Resources in a Congestion Zone are aggregated by QSE for each hour to create the QSE's aggregated planned operating level. If multiple Day Ahead Schedule validations are run on a particular day, only the first approved Day Ahead Schedule validation is used. Only hours when the zonal energy schedule is greater than zero (0) MW are considered in this measure.

An Occurrence is recorded for a Congestion Zone for a given hour if the QSE's zonal energy schedule and the aggregated planned operating level for that Congestion Zone differ by the greater of two percent (2%) of the zonal energy schedule or one (1) MW. Only one (1) Occurrence can be recorded per Congestion Zone per hour per QSE. To determine the QSE Measure Score for the Day Ahead Zonal Schedule Measure, Occurrences are summed for all Congestion Zones for every hour in a given month, and divided by the number of Congestion Zones multiplied by the total number of hours in that month where the QSE's zonal energy schedule in a Congestion Zone for a particular hour is greater than zero (0) MW.

This metric does not apply to WGR QSEs who submit ERCOT provided Resource Plans in compliance with Section 4.4.15, QSE Resource Plans.

[PRR800: Replace Section 4.10.5 above with the following upon system implementation.]

4.10.5 Day Ahead Schedule Measure

The "Day Ahead Schedule Measure" compares each QSE's energy schedule to the QSE's aggregated HSLs at the time a Day Ahead schedule validation, as described in Section 4.7, Validation and Correction of Schedule Data, is run and approved. The Resource Plan HSL is aggregated to include all On-line units, hydro units that have been tested hydro Responsive Reserve capability when synchronous condenser fast response mode, and active LaaRs for each QSE. The QSE's energy schedule and the aggregated HSLs for all twenty-four (24) hours of the next day are recorded at the time of the Day Ahead schedule validation. The highest value interval out of the four (4) fifteen (15)-minute Settlement Intervals in an Operating Hour is selected to represent the QSE's energy schedule. The HSLs for all Resources are aggregated by QSE for each Operating Hour to create the QSE's aggregated HSLs. If multiple Day Ahead schedule validations are run on a particular Operating Day, only the first approved Day Ahead schedule validation is used. Only Operating Hours when the energy schedule is greater than zero (0) MW are considered in this measure.

An Occurrence is recorded for a given Operating Hour if the QSE's energy schedule plus scheduled Ancillary Services are greater than the aggregated HSLs. The scheduled Ancillary Services include Regulation Service Up (RGSU) and response reserve schedules. Only one (1) Occurrence can be recorded per Operating Hour per QSE. To determine the QSE Measure Score for the Day Ahead Zonal Schedule Measure, Occurrences are summed for every Operating Hour in a given month, and divided by the total number of Operating Hours in that month where the QSE's energy schedule for a particular Operating Hour is greater than zero (0) MW.

4.10.6 Adjustment Period Zonal Schedule Measure

The "Adjustment Period Zonal Schedule Measure" compares each QSE's zonal energy schedule to the aggregated planned operating level for that Congestion Zone before the start of the Operating Hour. Each QSE's zonal energy schedule used to calculate this measure is taken at the end of the Adjustment Period. The last Resource Plan submitted before the start of the Operating Hour, but after the end of the Adjustment Period is used. The QSE's zonal energy schedules for each fifteen (15) minute interval in an hour are averaged over the entire hour to create the QSE's average zonal energy schedule. The planned operating level for all Resources in a Congestion Zone are aggregated by QSE for each hour to create the QSE's aggregated planned operating level. Only hours when the zonal energy schedule is greater than zero (0) MW are considered in this measure.

An Occurrence is recorded for a Congestion Zone for a given hour if the QSE's zonal energy schedule and the aggregated planned operating level for that Congestion Zone differ by the greater of two-percent (2%) of the zonal energy schedule or one (1) MW. Only one (1) Occurrence can be recorded per Congestion Zone per hour per QSE. To determine the QSE Measure Score for the Adjustment Period Zonal Schedule Measure, Occurrences are summed for all Congestion Zones for every hour in a given month, and divided by the number of Congestion Zones multiplied by the total number of hours in that month when the QSE's zonal energy schedule in a Congestion Zone for a particular hour is greater than zero (0) MW.

Any hour where a QSE that is not a WGR-only QSE updated its Resource Plan before the start of or during the Operating Hour, but after the end of the Adjustment Period and failed to pass this measure for that interval, will be excluded in the calculation of this measure. Any hour where a WGR-only QSE updated its Resource Plan for a Resource status change only and not changes in output due to changes in wind speed before the start of or during the Operating Hour, but after the end of the Adjustment Period, and failed to pass this measure for that interval will be excluded in the calculation of this measure.

4.10.7 Down Bid & Obligation Measure

The "Down Bid & Obligation Measure" reviews the consistency between the minimum mandatory Balancing Energy Service Down bid, the Regulation Service Down schedule, and the Resource Plan sustainable limits. Only hours where the energy schedule is greater than zero (0) MW are included in the calculation of this measure.

An Occurrence is recorded if the QSE's minimum mandatory Balancing Energy Service Down bid exceeds the QSE's actual zonal aggregated Balancing Energy Service Down bid by more than one (1) MW. The minimum mandatory Balancing Energy Service Down bids are calculated in accordance with the requirement established in Section 4.5.2, Receipt of QSE's Balancing Energy Bid Curves. An Occurrence may also be recorded if the QSE's Resource Plan aggregated LSL exceeds the sum of the QSE's energy schedule, Regulation Service Down schedule, and minimum mandatory Balancing Energy Service Down bid by more than one (1) MW. Only one (1) Occurrence can be recorded per QSE per hour per Congestion Zone.

To determine the QSE Measure Score for the Down Bid & Obligation Measure, Occurrences are summed for all Congestion Zones for every hour in a given month and divided by the number of Congestions Zones multiplied by the total number of hours in that month when the QSE's zonal energy schedule in a Congestion Zone for a particular hour is greater than zero (0) MW.

A QSE may request an exception to this measure for failing intervals for which the QSE has only a single Resource online in that Congestion Zone and is providing Down Regulation Service with that Resource. ERCOT shall grant the exception if provision of the Down Regulation

Service from the Resource prevents the QSE of the Resource from meeting the mandatory Balancing Energy Service Down bid requirement.

4.10.8 Total Up AS Scheduled Obligation Measure

The "Total Up AS Scheduled Obligation Measure" compares the energy schedule, Balancing Energy Service Up deployed, and scheduled Ancillary Services to the Resource Plan HSLs. The scheduled Ancillary Services include Regulation Service Up (RGSU), Responsive Reserve, and 30-Minute Non-Spinning Reserve Service (30MNSRS). The Resource Plan HSL is aggregated to include all On-line units, Off-line units necessary to cover Non-Spinning Reserve Service (NSRS) Obligations as specified in the Resource Plan, hydro units that have tested hydro Responsive Reserve capability when in synchronous condenser fast response mode, and active LaaRs for each QSE. Only fifteen (15) minute intervals when the sum of the RGSU schedule, Responsive Reserve Service (RRS) schedule, and NSRS schedule are greater than zero (0) MW are included in the calculation of this measure.

An Occurrence is recorded for a QSE in an interval if the sum of the QSE's energy schedule, Balancing Energy Service Up deployed, and scheduled Ancillary Services exceeds the QSE's Resource Plan aggregated HSL by more than one (1) MW. Only one (1) Occurrence can be recorded per QSE per interval. To determine the QSE Measure Score for the Total Up AS Schedule Obligation Measure, Occurrences are summed for every fifteen (15) minute interval in a given month, and divided by the total number of intervals in a given month when the QSE's scheduled Ancillary Services is greater than zero (0) MW.

The two (2) hours immediately following a Forced Outage of a Generation Resource will be excluded in the calculation of this measure.

4.10.9 Total Balancing Energy Service Up Bids for BES-Capable Non-Spinning Reserve Service (BESCNSRS) Measure

The "Total Balancing Energy Service Up Bids for BESCNSRS Measure" compares the quantity of Balancing Energy bids submitted for an hour to the total quantity of a QSE's NSRS Obligation that is being provided through utilization of generation capacity capable of being synchronized and ramped to a specific output level within fifteen (15) minutes that is also capable of providing Balancing Energy Service or Load that is capable of providing Balancing Energy Service.

An Occurrence is recorded for a QSE in an hour if the total Balancing Energy Service Up offer minus the BESCNSRS is less than zero (0) or the minimum price for the BESCNSRS-related Balancing Energy Service offer is less than the floor defined in Section 4.5.2, Receipt of QSE's Balancing Energy Bid Curves. Only one (1) Occurrence can be recorded per QSE per hour. To determine the QSE measure score for the Total Balancing Energy Service Up Bids for BESCNSRS Measure, Occurrences are summed for every hour of a given month and divided by the total number of hours in a given month when the QSE's scheduled NSRS obligation to be supplied by BESCNSRS is greater than zero (0) MW.

ERCOT Protocols
Section 5: Dispatch

May 22, 2009

5 DISPATCH

5.1 ERCOT Control Area Authority

5.1.1 Single Control Area

ERCOT will assume authority as Control Area Operator for the revised regional control area encompassing the boundaries of the previous control areas within the ERCOT interconnection.

5.1.2 Operating Guides and North American Electric Reliability Corporation Guidelines

ERCOT will perform all control area functions as defined in the Operating Guides and the North American Electric Reliability Corporation (NERC) guidelines.

5.2 North American Electric Reliability Corporation/ERCOT Tagging Procedures

The QSE will follow all NERC guidelines for tagging of Control Area interchange transactions. ERCOT will be operated as a single Control Area. Therefore, no internal ERCOT transactions require tagging. Only transactions across ERCOT interconnections to SPP, WSCC, or Mexico, will be tagged by the QSE as prescribed in the NERC tagging guidelines.

5.2.1 Standards and Practices

Each TSP, DSP, and Private Use Network must meet the requirements specified in Section 5.2.1, Standards and Practices, or at their option, meet alternative requirements specifically approved by ERCOT. Such alternative requirements may include requirements for aggregated groups of Facilities.

(1) Sufficient static Reactive Power capability shall be installed by a DSP or a Private Use Network not subject to a TDSP tariff in substations and on the distribution voltage system to maintain at least a ninety-seven hundredths (0.97) lagging power factor for the maximum net active power supplied from a substation transformer at its distribution voltage terminals to the distribution voltage system. In those cases where a Private Use Network's power factor is established and governed by a TDSP tariff, the TDSP and Private Use Network owner shall ensure that the Private Use Network meets the requirements as defined and measured in the applicable tariff. For any substation transformer serving multiple DSPs, this power factor requirement shall be applied to each DSP individually for its portion of the total Load served.

(2) Annually, ERCOT will review 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 Section 5.2.1, Standards and Practices. All DSP substations whose annual peak Load has exceeded ten (10) MW shall have and maintain Watt/VAR metering sufficient to monitor compliance; otherwise, DSPs will not be

required to install additional metering to determine compliance. At times selected by ERCOT, ERCOT will require manual power factor measurement at substations and points of interconnection that do not have power factor metering. ERCOT will endeavor to provide DSPs sufficient notice to perform the manual measurements. Such requests shall be limited to four (4) times per calendar year for each DSP substation or point of interconnection where power factor measurements are not available.

(3) All DSPs shall report any changes in their estimated net impact on ERCOT as part of the annual Load data assessment.

(4) 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 point of interconnection to the ERCOT Transmission Grid, based on the then current configuration (and the projected configuration if the configuration is going to change during the year) of the Generation Resource and any affiliated loads.

(5) If actual conditions indicate probable non-compliance, ERCOT will require power factor measurements at the time of its choice while providing sufficient notice to perform the measurements.

(6) Assuming optimal use of all other required installed Reactive Power capability, ERCOT Regional Planning Groups or Transmission Planning shall determine and demonstrate the need for any additional static and/or dynamic Reactive Power capability necessary to ensure compliance with the ERCOT Planning Criteria, and ERCOT Transmission Planning shall establish responsibility for any associated Facility additions among ERCOT TSPs.

(7) For monitoring of compliance of the TSP's planned Facilities to the ERCOT Planning Criteria performance requirements, a self-certification process with random audits (similar to compliance to NERC Planning Standards), in conjunction with work performed in the ERCOT Regional Planning Groups, shall be used. Except under Force Majeure conditions, if a TSP fails to maintain transmission system voltage within two percent (2%) of the scheduled voltage while reactive sources under its direct control are not fully utilized, ERCOT may, at its discretion, report this to the ERCOT Compliance Office.

(8) The ERCOT Compliance Office will investigate claims of alleged non-compliance using ERCOT compliance procedures. The ERCOT Compliance Office will use its compliance procedures to address confirmed non-compliance situations. The ERCOT Compliance Office will advise ERCOT and TSP planning and operating staffs of the results of such investigations.

5.2.2 Operating Standards

ERCOT and TDSPs shall operate the ERCOT System in compliance with Good Utility Practice and NERC and ERCOT standards, policies, guidelines and operating procedures. These Protocols shall control to the extent of any inconsistency between the Protocols and any of the following documents:

(1) Any reliability guides applicable to ERCOT, including the Operating Guides;

(2) The NERC Operating Manual and ERCOT procedures manual, supplied by NERC and ERCOT, respectively, as references for dispatchers to use during normal and emergency operations of the ERCOT Transmission Grid;

(3) Specific operating procedures, submitted to ERCOT by individual transmission Facility owners or operators to address operating problems on their respective grids that could affect operation of the interconnected ERCOT Transmission Grid; and

(4) Guidelines established by the ERCOT Board, which may be more stringent than those established by NERC for the secure operation of the ERCOT System.

5.2.3 Equipment Operating Limits

ERCOT Dispatch Instructions shall respect all equipment operating limits. Except as stated in Section 5.6, if a Dispatch Instruction conflicts with a restriction that may be placed on equipment from time to time by a TDSP or a Generation Resource's QSE to protect the integrity of equipment, ERCOT shall honor the restriction.

The TDSP will notify ERCOT of any limitations on the TDSP's system that may affect ERCOT Dispatch Instructions. ERCOT shall continuously maintain a posting on the Market Information System (MIS) of any TDSP limitations that may affect Dispatch Instructions. Any conflicts that cannot be satisfactorily resolved may be brought to ERCOT by any of the relevant affected Entities for investigation and resolution.

5.3 Routine Dispatch Duties of ERCOT

ERCOT will deploy Ancillary Services and dispatch transmission in accordance with these Protocols, including but not limited to Section 4, Scheduling, Section 5, Dispatch, and Section 6, Ancillary Services, respectively, including deploying Balancing Energy, Out of Merit (OOM), Replacement Reserve Resources, RMR Units, and Synchronous Condenser Units to ensure operational security and to remedy all Commercially Significant Constraints (CSC) and Operational Constraints.

ERCOT is the regional security coordinator for the ERCOT Region and is responsible for all regional security coordination as defined in the NERC Operating Manual and applicable ERCOT operating manuals or Operating Guides.

ERCOT may issue Dispatch Instructions to a TDSP (for the Real Time operation of Transmission Facilities) or to a QSE (for the Resources for which the QSE has scheduling responsibility.)

5.4 Dispatch Instructions

5.4.1 Control Area Operator Authority

ERCOT, as Control Area Operator (CAO), is authorized to take the following actions for the limited purpose of securely operating the ERCOT Transmission Grid in conformance with the standards specified in Section 5.2, Standards and Practices, including, but not limited to:

(1) Direct the physical operation of the ERCOT System, including circuit breakers, switches, voltage control equipment, protective relays, metering and Load shedding equipment;

(2) Call on Resources that have committed to provide Ancillary Services;

(3) Direct changes in the operation of voltage control equipment;

(4) Direct the implementation of OOM obligations and the use of RMR Service and transmission switching in order to prevent the violation of ERCOT System security limits; and

(5) Take those additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT System to a secure state in the event of an actual ERCOT System emergency.

5.4.2 Contents of Valid Dispatch Instructions

Dispatch Instructions consist of Verbal Dispatch Instructions and Dispatch Instructions issued via the Messaging System.

5.4.2.1 Verbal Dispatch Instructions

Valid verbal Dispatch Instructions shall contain the following information:

(1) Identification of the responsible Entity and instructing authority (to include ERCOT operator’s and receiving operator’s names);

(2) Specific Resources or TDSP Facilities that are the subject of the Dispatch Instruction;

(3) Specific action required;

(4) Current operating level or state of the Resources or TDSP Facilities that are the subject of the Dispatch Instruction;

(5) Operating level or state to which such Resources or Facilities will be dispatched;

(6) Time of notification of the Dispatch Instruction;

(7) Time at which the QSE or TDSP is required to initiate the Dispatch Instruction;

(8) Time within which the QSE or TDSP is required to complete the Dispatch Instruction; and

(9) Other information relevant to the specific Dispatch Instruction.

5.4.2.2 Dispatch Instruction via the Messaging System

Valid Dispatch Instructions issued via the messaging system shall contain the following information:

(1) Identification of the responsible Entity;

(2) Specific Resources that are the subject of the Dispatch Instruction;

(3) Specific action required;

(4) Time of notification of the Dispatch Instruction via a timestamp on the Dispatch Instruction;

(5) Time at which the QSE is required to initiate the Dispatch Instruction;

(6) Time within which the QSE is required to complete the Dispatch Instruction; and

(7) Other information relevant to the specific Dispatch Instruction.

5.4.3 Dispatch Instruction Procedures

The procedures for issuing and responding to Dispatch Instructions are as follows:

(1) All Dispatch Instructions to Resources — whether for dispatch of Ancillary Services, System Emergencies or any other reason — shall be directed to the QSE responsible for the affected Resource. ERCOT shall refrain from issuing dispatch instructions to generating units and other Resources undergoing testing with the exception of:

a) Dispatch instructions that are a part of the testing; or

b) During conditions when the generating unit is the only alternative for solving a transmission constraint; or

c) During Force Majeure Events that threaten the reliability of the system.

(2) Each QSE must immediately forward any valid Dispatch Instruction to the appropriate Resource or group of Resources or identify a reason for non-compliance to ERCOT in accordance with Section 5.4.4, Compliance with Dispatch Instructions.

(3) If ERCOT believes that a Resource or group of Resources has inadequately responded to a Dispatch Instruction, ERCOT shall notify the relevant QSE.

(4) The recipient of an oral Dispatch Instruction shall confirm the Dispatch Instruction by repeating it orally to ERCOT.

(5) The recipient of a written or electronic Dispatch Instruction shall acknowledge receipt of the Dispatch Instruction to ERCOT in writing or electronically, within one (1) hour.

(6) The recipient shall immediately request clarification of the Dispatch Instruction if the recipient fails to understand its responsibility under the Dispatch Instruction.

(7) ERCOT shall record all voice conversations that occur in the communication of Dispatch Instructions.

(8) ERCOT will record or file all written or electronic Dispatch Instructions and acknowledgements as soon as practicable after the issuance of the Dispatch Instruction.

(9) By mutual agreement of the QSE and ERCOT, Dispatch Instructions to the QSE may be provided to the QSE's designated agent.

(10) By mutual agreement of the TDSP and ERCOT, Dispatch Instructions to the TDSP may be provided to the TDSP's designated agent.

5.4.4 Compliance with Dispatch Instructions

(1) Each TDSP and each QSE within the ERCOT System shall comply fully and promptly with valid Dispatch Instructions, unless in the sole and reasonable judgment of the TDSP or QSE, such compliance would create a threat to safety, risk of bodily harm or damage to the equipment, or is otherwise not in compliance with these Protocols.

(2) If the recipient of a valid Dispatch Instruction does not comply because in the sole and reasonable judgment of the TDSP or QSE, such compliance would create a threat to safety, risk of bodily harm or damage to the equipment, or is otherwise not in compliance with these Protocols, then, the TDSP 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 will immediately notify ERCOT of the conflict and request resolution.

(4) Upon receipt of notice of non-compliance or conflict with Dispatch Instructions, ERCOT may, but is not required to, issue new Dispatch Instructions in response to the TDSP or QSE's notice.

(5) ERCOT's final instruction in effect will apply for all Protocol-related processes. If the QSE does not comply after receiving the final instruction, the QSE shall remain liable for failure to meet its obligations under the Protocols and shall remain liable for any charges resulting from such failure.

(6) ERCOT's final instruction to a TDSP in effect will apply for all Protocol-related processes. If the TDSP does not comply after receiving the final instruction, the TDSP shall remain liable for such failure under these Protocols in accordance with the TDSP's Agreement with ERCOT.

(7) In all cases in which compliance with a Dispatch Instruction is disputed, both ERCOT and the QSE or TDSP shall document their communications, agreements, disagreements, and reasons for their actions, to enable resolution of the dispute through the ADR process in Section 20, Alternative Dispute Resolution.

5.5 Changes in ERCOT System Status

5.5.1 Changes in Resource Status

The Qualified Scheduling Entity (QSE) will notify ERCOT of an unplanned change in Resource status as soon as practicable following the change. The QSE representing the Resource will report any changes in Resource status to ERCOT in the Resource Plan by the beginning of the next hour following the change in status.

(1) When the operating mode of a Generation Resource required to provide Voltage Support Service (VSS) Automatic Voltage Regulator (AVR) or Power System Stabilizer (PSS) is changed while the unit is operating, the QSE shall promptly inform ERCOT. The QSE shall also supply AVR or PSS status logs to ERCOT upon request.

(2) Any short-term inability of a Generation Resource required to provide VSS to meet its reactive capability requirements shall be immediately reported to ERCOT and the Transmission Service Provider (TSP).

(3) A change in output of a Wind-powered Generation Resource (WGR) due to varying wind speed is not a Resource status change.

5.5.2 Changes in Transmission Facility Status

The TDSP will notify ERCOT of any changes in status of Transmission Facility elements as provided and clarified in the ERCOT procedures. The TDSP will notify ERCOT of any other Transmission Facility status as soon as practicable following the change. In addition, any short-term inability to meet minimum TSP or DSP reactive requirements shall be immediately reported to ERCOT by way of the TSP.

5.6 Emergency and Short Supply Operation

5.6.1 Introduction

ERCOT, as the single Control Area Operator, is responsible for maintaining reliability in normal and emergency operating 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 North American Electric Reliability Corporation (NERC) standards and include, but are not limited to:

(1) Minimum operating reserve levels;

(2) Criteria for determining acceptable operation of the frequency control system;

(3) Criteria for determining and maintaining system voltages within acceptable limits;

(4) Criteria for maximum acceptable transmission equipment loading levels; and

(5) Criteria for determining when ERCOT is subject to unacceptable risk of widespread cascading outages.

In implementing these Protocols, ERCOT shall, to the fullest extent practicable, utilize market tools as prescribed in these Protocols before implementing command and control actions, such as OOMC, OOME, or RMR Service. It is anticipated that, with effective and timely communication, the tools available to ERCOT from the market will avert most threats to the reliability of the ERCOT System. However, these Protocols shall not preclude ERCOT from taking other actions to preserve the integrity of the ERCOT System.

5.6.2 Communication

Good, accurate, and timely communication between ERCOT, TDSPs, and QSEs is essential. The QSEs must be provided adequate information to make informed decisions and must receive the information with sufficient advance notice to facilitate generation and/or Load responses.

The type of communication ERCOT will issue will be 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.

ERCOT shall consider the severity of the potential Emergency Condition as it determines which of the communications set forth in Section 5.6.3, Operating Condition Notice, through Section 5.6.6, Emergency Notice, to use. The severity of the Emergency Condition may be limited to an isolated local area affecting a small number of megawatts, or cover large areas affecting several hundred megawatts, or may be an ERCOT-wide condition potentially affecting all of the ERCOT Region.

The following sections describe the types of communications that will be issued by ERCOT to inform all QSEs and TDSPs of the operating situation. These communications may relate to transmission, distribution, and/or generation. The communications shall specify the severity of the situation, the area affected, the areas potentially affected, and the anticipated duration of the Emergency Condition.

5.6.3 Operating Condition Notice

ERCOT will issue an Operating Condition Notice (OCN) to inform all QSEs 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 extra 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.

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 simply serves as a reminder to QSEs and TDSPs that some attention to the changing condition 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.

Reasons for OCNs include unplanned transmission outages, and weather related concerns such as anticipated freezing temperatures, hurricanes, wet weather, and ice storms.

ERCOT will monitor actual and forecasted weather for ERCOT and adjacent NERC regions. When adverse weather conditions are expected, ERCOT may confer with TDSPs 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 their fuel capabilities. Requests for this type of information shall be for a time period of no more than seven (7) days from the date of the request. The specific information which 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.

QSEs and TDSPs 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.

5.6.4 Advisory

ERCOT will issue an Advisory for informational purposes for the following reasons:

(1) 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;

(2) When weather or ERCOT System conditions require more lead-time than the normal Day Ahead market allows;

(3) When communications or other controls are significantly limited; or

(4) When ERCOT Transmission Grid conditions are such that operations within first contingency criteria as defined in the Operating Guides are not likely or possible because of Forced Outages or other conditions.

The Advisory communicates existing constraints. ERCOT will notify TDSPs and QSEs. QSEs will notify appropriate Resources and LSEs. ERCOT will communicate with TDSPs 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.

Although an Advisory is for information purposes, ERCOT may exercise its authority, in such circumstances, to increase Ancillary Service requirements above the quantities specified in the normal Day Ahead plan in accordance with scheduling procedures. ERCOT may also increase the Day Ahead market to Two Days Ahead. ERCOT may require information from QSEs representing Resources regarding their fuel capabilities. Requests for this type of information shall be for a time period of no more than seven (7) days from the date of the request. The specific information which 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.

If the Advisory is the result of a short supply situation, each QSE with extra generating capacity that is normally not readily available due to ramp rate limitations (e.g., extra capacity on combined-cycle combustion turbines utilizing duct firing), may update their Up Balancing bid curve to reflect the extra capacity that can be made available in thirty (30) minutes or less. To prevent the deployment of such extra capacity, the HSL shall be adjusted down to a level equal to the HOL rating of the online Resource minus the amount of extra capacity bid into the Up Balancing minus the Ancillary Services obligation.

5.6.5 Watch

ERCOT will issue a Watch when ERCOT determines:

(1) That conditions have developed such that additional Ancillary Services are needed in the Operating Period;

(2) That market Congestion Management techniques specified in these Protocols will not be adequate to resolve transmission problems; or

(3) Forced Outages or other abnormal operating conditions occur which require operations outside first contingency security limits as defined in the ERCOT Operating Guides;

(4) That there are insufficient Ancillary Service bids.

ERCOT will post the Watch electronically and will notify all TDSPs and QSEs via the Messaging System of the posted Watch(es).

ERCOT must issue a Watch before acquiring Emergency Short Supply Regulation Services (RGS), Emergency Short Supply Responsive Reserve Services (RRS) or Emergency Short Supply Non-Spinning Reserve Services (NSRS). With the issuance of a Watch pursuant to item (1) or (4) above, ERCOT may exercise its authority to immediately procure the following services from existing bids:

(1) RGS;

(2) RRS; and

(3) NSRS.

Emergency Short Supply RGS, Emergency Short Supply RRS or Emergency Short Supply NSRS will be procured if there is insufficient availability of bids for any of the listed Ancillary Services.

ERCOT will post the Watch electronically on the Market Information System (MIS) and will notify all TDSPs and QSEs via the Messaging System of the posted Watch(es).

Corrective actions identified by ERCOT shall be communicated through Dispatch Instructions to TDSPs and/or QSEs required to implement the corrective action. Each QSE shall immediately notify the Market Participants that it represents of such Watch. To minimize the effects on the ERCOT System, all TDSPs will identify and prepare to implement actions, including restoring outaged lines as appropriate and preparing for Load shedding. ERCOT may instruct TDSPs to reconfigure ERCOT System elements as necessary to improve the reliability of the ERCOT System. On notification of a Watch, each QSE and TDSP will prepare for an emergency in case conditions worsen. ERCOT may require information from QSEs representing Resources regarding their fuel capabilities. Requests for this type of information shall be for a time period of no more than seven (7) days from the date of the request. The specific information which 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.

5.6.6 Emergency Notice

ERCOT will issue an Emergency Notice only for the following reasons:

(1) ERCOT cannot maintain minimum reliability standards (for reasons including fuel shortages) during the Operating Period using every Resource practicably obtainable from the market;

(2) ERCOT is in an unreliable condition, as defined below;

(3) Immediate action must be taken to avoid or relieve an overloaded transmission element; or

(4) ERCOT varies from timing requirements or omits one or more scheduling procedures, as described in Section 4.8, Temporary Deviations from Scheduling Procedures.

The actions ERCOT takes during an Emergency Condition will depend on the nature and severity of the situation.

ERCOT is considered to be in an unreliable condition whenever ERCOT Transmission Grid status is such that the most severe single-contingency event presents the threat of uncontrolled separation or cascading outages and/or large-scale service disruption to Load (other than Load being served from radial transmission service) and/or overload of a critical transmission element, and no timely solution is obtainable from the market.

If the Emergency Condition is the result of a transmission problem that puts ERCOT in an unreliable condition, then ERCOT will act immediately to return ERCOT to a reliable condition, including instructing Resources to change output and instructing TDSPs to drop Load.

If the Emergency Condition is the result of a short supply situation, each QSE having bid extra capacity during the Advisory period that is normally not readily available due to ramp rate limitations, will immediately update their HSL of any online Resource that is capable of providing extra capacity within thirty (30) minutes. The HSL shall be set to equal the HOL rating of the online Resource minus the Ancillary Services Obligation. The extra capacity must already be part of the QSE's Up Balancing bid curve in order for Scheduling, Pricing and Dispatch (SPD) to utilize the updated HSL.

If the short supply Emergency Condition continues, then the Energy Emergency Alert (EEA) procedures will be followed.

5.6.6.1 Energy Emergency Alert (EEA)

At times it may be necessary to reduce electrical Demand because of a temporary decrease in available electricity supply. To provide orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT will initiate and coordinate the implementation of the EEA following the EEA levels set forth below in Section 5.6.7, EEA Levels.

The objective of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT Transmission Grid in order to reduce the chance of cascading outages.

ERCOT's operating procedures shall meet the following goals while continuing to respect the confidentiality of market sensitive data:

(1) Use of the market to the fullest extent practicable without jeopardizing the reliability of the ERCOT System;

(2) Use of Responsive Reserve Services and other Ancillary Services to the extent permitted by ERCOT System conditions;

(3) Maximum use of ERCOT System capability;

(4) Maintenance of station service for nuclear Generation Resource Facilities;

(5) Securing of startup power for Generation Resources;

(6) Operation of power Generation Resources during loss of communication with ERCOT;

(7) Restoration of service to critical Loads in the manner defined in the Operating Guides; and

(8) Restoration of service to all Customers following major system disturbances, giving priority to the larger groups of Customers.

ERCOT shall be responsible for coordinating with QSEs and TDSPs to monitor system conditions, initiating the EEA levels, notifying all QSEs, and coordinating the implementation of the EEA levels while maintaining transmission security limits.

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

During the EEA, ERCOT has the authority to obtain energy from Direct Current (DC) Ties or Block Load Transfers (BLTs) from non-ERCOT Control Areas when capacity is available.

Some of the EEA levels will not be applicable if transmission security violations exist. There may be insufficient time to implement all levels in sequence, but to the extent practicable, ERCOT will use Ancillary Services which bidders have made available in the market to maintain or restore reliability.

ERCOT may immediately implement EEA Level 3 any time the steady-state system frequency is below 59.8 Hz and will immediately implement EEA Level 3 any time the steady-state frequency is below 59.5 Hz.

Percentages for EEA Level 3 Load shedding will be based on previous year's TDSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

5.6.6.2 General Procedures Prior to EEA Operations

Prior to declaring EEA Level 1 detailed in Section 5.6.7, EEA Levels, ERCOT shall:

(1) Start RMR units available in the time frame of the emergency. RMR units should be loaded to full capability;

(2) Issue Dispatch Instructions to QSEs to suspend any ongoing ERCOT required generating unit or Resource performance testing;

(3) Utilize available Resources providing 30-Minute Non-Spinning Reserve Services (30MNSRS) that can be deployed to increase Responsive Reserves; and

(4) ERCOT shall use the Reserve Discount Factor (RDF) for the purpose of monitoring Physical Responsive Capability (PRC). The PRC will be used by ERCOT to determine the appropriate Emergency Notification and EEA levels.

5.6.7 EEA Levels

EEA Level 1 — Maintain ERCOT Physical Responsive Capability (PRC) on Resources plus RRS MW provided from LaaR Equal to 2300 MW.

ERCOT will:

(1) Utilize available DC Tie capability that is not already being used by the market;

(2) Notify the Southwest Power Pool (SPP) Security Coordinator; and

(3) Issue Out of Merit Order (OOM) Dispatch Instructions to uncommitted units available within the expected timeframe of the emergency.

(4) Inquire about availability of BLTs.

QSEs will:

(1) Notify ERCOT of any Resources uncommitted but available in the timeframe of the emergency.

(2) Immediately update the HSL of any On-line Resource that is capable of providing extra capacity within thirty (30) minutes. The extra capacity must already be part of the QSE’s Up Balancing bid curve in order for SPD to utilize the updated Resource Plan.

EEA Level 2A — Maintain ERCOT Physical Responsive Capability (PRC) on Resources plus RRS MW Provided from LaaR Equal to 1750 MW.

In addition to measures associated with EEA Level 1, ERCOT will:

(1) Instruct TDSPs to reduce Customers' Load by using distribution voltage reduction measures, if deemed beneficial by the TDSP;

(2) Instruct QSEs to deploy all Responsive Reserve, which is supplied from Load acting as a Resource (LaaR) (controlled by high-set under-frequency relays); and

(3) With the approval of the affected non-ERCOT Control Area, may instruct TDSPs to implement BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas. Use of a BLT will be defined in the ERCOT Operating Guides.

EEA Level 2B – Maintain system frequency at 60 Hz:

Following deployment of the measures associated with EEA Level 1 and Level 2A, ERCOT will deploy all available Emergency Interruptible Load Service (EILS) Resources as a single block via a single Verbal Dispatch Instruction to all QSEs providing EILS.

Unless a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation.

EEA Level 3 — Maintain system frequency at 59.8 Hz or greater

In addition to measures associated with EEA Levels 1, 2A and 2B, ERCOT will direct all TDSPs and their agents to shed firm Load, in one hundred (100) megawatt (MW) blocks, distributed as agreed and documented in the ERCOT Operation procedures in order to maintain a steady state system frequency of 59.8 Hertz (Hz). ERCOT may take this action prior to the expiration of the ten (10) minute EILS Resource deployment period if ERCOT, in its sole discretion, believes that shedding firm Load is necessary to maintain the stability of the ERCOT System. If, due to ERCOT System conditions, EILS Resources are not deployed prior to this action, ERCOT shall deploy EILS Resources as soon as possible following this action.

In addition to measures associated with EEA Levels 1, 2A and 2B, TDSPs will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TDSPs shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

5.6.7.1 Restoration of Market Operations

ERCOT shall continue the EEA until sufficient bids are received and deployed by ERCOT to eliminate the conditions requiring the EEA. ERCOT shall release EILS Resources after both the restoration of RRS capacity and initiation of the restoration of Loads acting as Resources.

Upon ERCOT notifying the market that the EEA is cancelled, each QSE that enabled extra capacity during Emergency Condition or EEA will remove the extra capacity from the Up Balancing bid stack and adjust the HSL of any online Resource within fifteen (15) minutes to a level that ensures compliance with all applicable standards.

5.6.8 Emergency Compensation

Deployment and compensation for OOMC and OOME Resources that ERCOT deploys due to a supply-related emergency will be according to Section 6.8.2, Capacity and Energy Payments for Out-of-Merit or Zonal OOME Service.

There will be no compensation other than normal settlement methods to Resources for the utilization of stranded capacity.

There will be no compensation other than normal settlement methods to Loads in the event of Load shedding by the TDSP during EEA.

When energy is delivered to the ERCOT Control Area from a non-ERCOT Control Area through emergency instructions across a DC Tie, the DC Tie will be treated as a Resource receiving an OOME instruction via its associated QSE(s) in the Congestion Zone in which the DC Tie is located. For settlement purposes, the Resource Plan of the DC Tie Resource shall be set to zero (0).

When energy is delivered from the ERCOT Control Area through an emergency Dispatch Instruction across a DC Tie, the DC Tie will be treated as Load in the Congestion Zone in which the DC Tie is located. The QSE(s) associated with the DC Tie used to deliver energy from the ERCOT Control Area is responsible for any applicable fees and charges as described in Section 4.4.18.4, Settlement.

5.7 Block Load Transfers between ERCOT and Non-ERCOT Control Areas

Under Watch, EEA, or other Emergency Conditions, it may be necessary for ERCOT to request the implementation of Block Load Transfer (BLT) schemes which will transfer Loads normally located in the ERCOT Control Area to a non-ERCOT Control Area. Similarly, when non-ERCOT Control Areas experience certain transmission contingency or short supply conditions, it may be necessary for ERCOT to agree to the implementation of BLT schemes which will transfer Loads normally located in a non-ERCOT Control Area to the ERCOT Control Area. BLTs will be restricted to the following conditions:

(1) BLTs shall occur only under a specific Dispatch Instruction from ERCOT.

(2) BLTs that are looped systems may be tied to the other Control Area’s electrical system through multiple interconnection points at the same time. Transfers of looped configurations will be permitted only if all interconnection points are netted under a

single Electric Service Identifier (ESI ID). Individual meter points for looped system BLTs must be within the same Congestion Zone.

(3) BLTs of Load to the ERCOT Control Area will be:

(i) Treated as non-competitive wholesale Load in the ERCOT settlement system,

(ii) Registered in a manner similar to that of Non-Opt In Entities (NOIEs), and

(iii) Responsible for Unaccounted For Energy (UFE) allocations and Transmission Losses consistent with similarly situated NOIE metering points.

(4) BLTs of Load to the ERCOT Control Area will be permitted only if such transfers will not jeopardize the reliability of the ERCOT System. Under an ERCOT Emergency Notice, BLTs that have been implemented may be curtailed or terminated by ERCOT in order to maintain the reliability of the ERCOT System.

(5) BLTs of Load from the ERCOT Control Area will be treated as a Resource in the ERCOT settlement system.

(6) BLTs of Load from the ERCOT Control Area will be sent Dispatch Instructions only with the permission of the affected non-ERCOT Control Area. Under emergency conditions, BLTs that have been implemented may be curtailed or terminated by the non-ERCOT Control Area in order to maintain the reliability of the non-ERCOT system.

(7) Restoration of service to outage Customers using BLTs will be accomplished, as quickly as possible, if the transfers will not jeopardize the reliability of the ERCOT System and only under specific Dispatch Instruction from ERCOT.

(8) The necessary Market Participant agreements, metering, and ERCOT settlement systems are in place prior to the implementation of any BLT.

(9) Transmission BLT metering points utilized five (5) or more time per year, as monitored by the Transmission and/or Distribution Service Provider (TDSP), will conform to ERCOT Polled Settlement (EPS) metering requirements as defined in Section 10, Metering, and the Settlement Metering Operating Guide. BLT metering points that are Distribution Systems or are transmission BLT metering points used less than five (5) times per year will be Revenue Quality Meters, four (4) channel bi-directional kWh/kVARh, fifteen (15) minute Interval Data Recorder (IDR) metering with remote interrogation. ERCOT may impose additional metering requirements as deemed necessary to ensure ERCOT System reliability and integrity.

5.7.1 BLT Data Model in ERCOT Systems

Each BLT point which will transfer loads normally located in the ERCOT control area to a Non-ERCOT control area will be established as a pseudo generation facility and designated as such in ERCOT systems. Each BLT point which will transfer loads normally located in a Non-ERCOT control area to the ERCOT control area will have an ESI ID associated with it and will be treated as load in the ERCOT systems.

5.7.2 Registration of BLT Points

BLTs that block ERCOT Load into a Non-ERCOT Control Area will be treated as a Resource by ERCOT and assigned a Resource ID. An ERCOT registered Resource Entity; with an ERCOT registered QSE affiliation must complete the applicable Asset Registration forms. This Asset registration form along with the Metering Design Documentation will be the basis for establishing the ERCOT Data Model.

BLTs that block Non-ERCOT Load into the ERCOT Control Area will be treated as a non-competitive wholesale Load by ERCOT and assigned an ESID. The TDSP associated to the BLT point has the responsibility for creation and maintenance of BLT ESI IDs. Distribution BLTs points located behind NOIE metering points do not require an ESI ID. An ERCOT registered LSE, with an ERCOT registered QSE affiliation, must be assigned to the ESI ID associated to BLT Point.

5.7.3 Scheduling & Operation of BLTs

BLTs will be treated as a Resource of the QSE associated with a BLT metering point. However, the QSE will not be required to provide the real time data to ERCOT normally provided for Resources. ERCOT shall confirm its availability with the Non-ERCOT Control Area or the TDSP prior to issuing any Dispatch Instructions to the QSE and the TDSP. Any energy delivered under such a Dispatch Instruction shall be treated as an OOME Dispatch Instruction to the QSE. For settlement purposes, the Dispatch Instruction will be treated as an instructed deviation and the Resource Plan of the BLT Resource shall be set to zero.

Generation Resources connected to the ERCOT System included in the BLT are under no obligation to provide Ancillary Services or any other services while that transmission area is connected to a non-ERCOT Control Area other than through a DC Tie.

The QSE of the LSE assigned to the ESI ID associated with a BLT point will include that Load in its Balanced Schedules.

5.7.4 Settlement of BLT Points

When ERCOT load is blocked into a Non-ERCOT control area, the energy delivered to ERCOT load through a BLT will be treated as generation into the Congestion Zone in the settlement system. The generation and dispatch instruction will be attributed to the Resource registered for that BLT point. ERCOT customers, customer’s REPs, and REP’s QSEs served by a Non-ERCOT control area through a BLT will not be impacted by the switch to a Non-ERCOT resource. ERCOT will settle with all parties through the ERCOT settlement process.

When a Non-ERCOT control area load is blocked into ERCOT, the energy delivered to the Non-ERCOT control area through a BLT will be treated as load in the Congestion Zone in the settlement system. The QSE of the LSE assigned to the ESI ID associated with the BLT point load is responsible for any applicable fees and charges as described in Section 9, Settlement and Billing.

5.8 DC Ties and BLTs with the CFE Control Area

Under Watch, Energy Emergency Alert (EEA) or other Emergency Condition which may negatively affect the reliability of the ERCOT System, it may be necessary for ERCOT to request energy from Direct Current (DC) Ties and Block Load Transfers (BLTs) with the Comision Federal de Electricidad (CFE) Control Area in accordance with an agreement between CFE and ERCOT.

Similarly, when the CFE Control Area experiences certain reliability contingency or short supply conditions, it may be necessary for ERCOT to allow energy to be delivered to the CFE Control Area.

Deliveries to and from the CFE Control Area over the CFE/ERCOT DC Ties or in the form of BLTs shall be restricted to the following conditions:

(1) Deliveries of energy from the ERCOT Control Area to the CFE Control Area will be permitted only if such transfers do not jeopardize the reliability of the ERCOT System. Under an Advisory, Watch, EEA or other Emergency Condition, ERCOT may curtail or terminate deliveries to CFE that have been scheduled or implemented in order to maintain the reliability of the ERCOT System.

(2) Under Emergency Conditions, CFE may curtail deliveries to the ERCOT Control Area in order to maintain the reliability of the CFE system.

5.9 Frequency Response Requirements and Monitoring

5.9.1 Generation Resource and QSE Participation

5.9.1.1 Governor in Service

At all times a Generation Resource is on line, its turbine governor shall remain in service and be allowed to respond to all changes in system frequency. Generation Entities shall not reduce governor response on individual Resources during abnormal conditions without ERCOT's consent (conveyed by way of the Generation Entity's QSE) unless equipment damage is imminent.

5.9.1.2 Reporting

Generation Entities shall conduct applicable generating governor speed regulation tests on Resources as specified in the Operating Guides. Test results and/or other relevant information shall be reported to ERCOT and ERCOT shall forward results to the appropriate TSPs.

Resource governor modeling information required in the ERCOT Planning Criteria shall be determined from actual Resource testing described in the Operating Guides. Within thirty (30) days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the connected TSP.

When the governor of a Generation Resource is blocked while the Resource is operating, the QSE shall promptly inform ERCOT. The QSE shall also supply governor status logs to ERCOT upon request.

Any short-term inability of a Generation Resource to supply governor response shall be immediately reported to ERCOT.

If a Generation Resource trips Off-line due to governor response problems, the Generation Entity shall immediately report the change in the status of the Resource to ERCOT and the QSE.

5.9.2 Primary Frequency Control Measurements

For the purposes of this section, the A Point is the last stable frequency value prior to a frequency disturbance. For a decreasing frequency event with the last stable frequency value of 60.000 Hz or below, the actual frequency is used. For a decreasing frequency event with the last stable frequency value between 60.000 and 60.036 Hz, 60.000 Hz will be used. For a decreasing frequency event with the last stable frequency value above 60.036 Hz, actual frequency will be used. For an increasing frequency event with the last stable frequency value of 60.000 or above, the actual frequency is used. For an increasing frequency event with the last stable frequency between 59.964 and 60.000 Hz, 60.000 Hz will be used. For an increasing frequency event with the last stable frequency value of 59.964 or below, the actual frequency is used. ERCOT shall determine the A Point frequency for each event.

For the purposes of this section, the C Point is the lowest frequency value during the first five seconds of the event.

For the purposes of this section, the B Point is the "recovery" frequency value after the C Point. The B Point should occur after full governor response of the turbines has occurred, usually between ten (10) and thirty (30) seconds after the A Point, but not greater than sixty (60) seconds after the A Point. ERCOT shall determine the B Point for each event.

B Point Plus Thirty Seconds: At thirty seconds following the B Point, an analysis will be performed by ERCOT with the assistance of the appropriate ERCOT subcommittee to determine if primary frequency control response is sustained.

For the purposes of this section, a "Measurable Event" is the sudden change in interconnection frequency that will be evaluated for performance compliance will have i) a frequency B Point between 59.700 Hz and 59.900 Hz or between 60.100 Hz and 60.300 Hz, and ii) a difference between the B Point and the A Point greater than or equal to +/- 0.100 Hz.

5.9.2.1 ERCOT Required Primary Frequency Control Response

The combined response of all Generation Resources interconnected in ERCOT to a Measurable Event shall be at least 420 MW / 0.1 Hz. This value should be reviewed on an annual basis by ERCOT and the appropriate ERCOT subcommittee for system interconnect reliability needs.

ERCOT will evaluate, with the assistance of the appropriate ERCOT subcommittee, primary frequency control response during Measurable Events. The actual Generation Resource response will be compiled to determine if adequate primary frequency control participation was available.

ERCOT and the appropriate ERCOT subcommittee will review each Measurable Event, verifying the reasonableness of data. Data that is in question may be requested from the QSE for comparison and/or individual Resource data may be retrieved from ERCOT's database.

ERCOT's performance will be averaged using the most recent six (6) Measurable Events to determine its rolling average contribution.

5.9.3 ERCOT Data Collection

5.9.3.1 Data Collection

ERCOT will collect all data necessary to analyze each Measurable Event. This will include the following real-time data:

(1) Interconnection Frequency;

(2) Regulation Service deployed;

(3) Responsive Reserve Service deployed;

(4) QSE available Responsive Reserve Service;

(5) QSE total Generation;

(6) QSE SCE;

(7) QSE Bias;

(8) QSE LaaR MW;

(9) LaaR deployed;

(10) QSE Responsive Reserve Service;

(11) ERCOT Load and individual Resource(s) that contributed to the frequency deviation; and

(12) EILS deployed.

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Section 6: Ancillary Services

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6 ANCILLARY SERVICES

6.1 Ancillary Services Required by ERCOT

ERCOT shall be responsible for developing a daily Ancillary Services Plan with sufficient Ancillary Services (AS) to maintain the security and reliability of the ERCOT System consistent with ERCOT and North American Electric Reliability Corporation (NERC) standards. The Ancillary Services required by ERCOT are described below. ERCOT shall procure and deploy Ancillary Services on behalf of QSEs.

6.1.1 Balancing Energy Service

As provided by ERCOT to the Qualified Scheduling Entities (QSEs): Balancing Energy is deployed by ERCOT with the goals that (1) Regulation Service in either direction not be depleted during the interval, and (2) Regulation Service up and down energy is deployed in each Settlement Interval such that the net energy in regulation is minimized.

As provided by a QSE to ERCOT: The provision of incremental or decremental energy dispatched by Settlement Interval to meet the balancing needs of the ERCOT System.

6.1.2 Regulation Service – Down

As provided by ERCOT to the QSEs: Regulation-down power is deployed in response to an increase in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

As provided by a QSE to ERCOT: The provision of Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

6.1.3 Regulation Service-Up

As provided by ERCOT to the QSEs: Regulation up power is deployed in response to a decrease in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

As provided by a QSE to ERCOT: The provision of Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

6.1.4 Responsive Reserve Service

As provided by ERCOT to the QSEs: Operating reserves ERCOT maintains to restore the frequency of the ERCOT System within the first few minutes of an event that causes a significant deviation from the standard frequency. Furthermore, Responsive Reserve Service provides reserved Resources that are deployed for the Operating Hour in compliance with these Protocols in response to loss-of-Resource contingencies on the ERCOT System.

As provided by a QSE to ERCOT: The provision of capacity by unloaded Generation Resources that are on line, Load Resources capable of controllably reducing or increasing consumption under dispatch control (similar to Automatic Generation Control (AGC)) and that immediately responding proportionally to frequency changes (similar to generator governor action), and Resources controlled by high set under-frequency relays or from Direct Current Tie (DC Tie) response. The amount of capacity from unloaded Generation Resources or DC Tie response is limited to the amount allowed in the Operating Guides or that, which can be deployed within 15-seconds.

6.1.5 Non-Spinning Reserve Service

As provided by ERCOT to the QSEs: Reserves maintained by ERCOT, that are deployed for the Operating Hour in response to loss-of-Resource contingencies on the ERCOT System.

As provided by a QSE to ERCOT: Resources that are providing 30-Minute Non-Spinning Reserve Service (30MNSRS) or BES-Capable Non-Spinning Reserve Service (BESCNSRS).

6.1.6 Replacement Reserve Service

As provided by ERCOT to the QSEs: The instruction, by ERCOT, for the deployment of Loads or non-synchronized Generation Resources in order to make available additional Balancing Energy Service.

As provided by a QSE to ERCOT: A Resource capable of providing additional Balancing Energy Service to ERCOT when deployed.

6.1.7 Voltage Support

As provided by ERCOT to the QSEs and the TDSPs: The coordinated scheduling of Voltage Profiles at transmission busses to maintain transmission voltages on the ERCOT System in accordance with Operating Guides.

As provided by a QSE to ERCOT: The provision of capacity from a Generation Resource required to provide VSS, whose power factor and output voltage level can be scheduled by ERCOT to maintain transmission voltages within acceptable limits throughout the ERCOT System in accordance with Operating Guides.

6.1.8 Black Start Service

As provided by ERCOT to QSEs: The procurement by ERCOT through Agreements, pursuant to emergency Dispatch by ERCOT and emergency restoration plans of Resources which are capable of self-starting or Resources within close proximity of another power pool which are capable of starting from such power pool via a firm standby power supply contract, without support from the ERCOT System, or transmission equipment in the ERCOT System in the event of a blackout, in order to begin restoration of the ERCOT System to a secure operating state. Resources which can be started with a minimum of pre-coordinated switching operations using ERCOT transmission equipment within the ERCOT System may be considered for Black Start Service only where switching may be accomplished within one (1) hour or less.

As provided by a Generator or a QSE to ERCOT: The provision of Resources under a Black Start Agreement, pursuant to emergency Dispatch, which are capable of self-starting or Resources within close proximity of another power pool which are capable of starting from such power pool via a firm standby power supply contract, without support from the ERCOT System, or transmission equipment in the ERCOT System in the event of a blackout. Resources which can be started with a minimum of pre-coordinated switching operations using ERCOT transmission equipment within the ERCOT System may be considered for Black Start Service only where switching may be accomplished within one (1) hour or less.

6.1.9 Reliability Must-Run Service

As provided by ERCOT to QSEs: Agreements for capacity and energy from Resources which otherwise would not operate and which are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria, as described in the Operating Guides. This includes service provided by RMR Units and MRA Resources.

As provided by a QSE to ERCOT: The provision of Generation Resource capacity and/or energy Resources under a Reliability Must-Run (RMR) Agreement or a Must Run Alternative (MRA) Agreement, including Agreements with Synchronous Condenser Units, whose operation is directed by ERCOT.

6.1.10 Out of Merit Capacity Service

As provided by ERCOT to QSEs: The provision by ERCOT of Out of Merit Order (OOM) Replacement Reserve Service from Generation Resources, that would otherwise not be selected to operate because of their place (or absence) in the Merit Order of Resources' bids for Ancillary Services. OOMC is used by ERCOT to provide for the availability of sufficient capacity so that Balancing Energy bids are available to solve capacity insufficiency, Congestion, or other reliability needs. Loads Acting as Resources will not be available to ERCOT to provide OOMC Service.

As provided by a QSE to ERCOT: Generation capable of providing additional Balancing Energy Service to ERCOT when deployed.

6.1.11 Out-Of-Merit Energy Service

As provided by ERCOT to QSEs: The deployment by ERCOT for the Settlement Interval of energy from Resources, that may or may not have provided Resource-specific premium bids, and used by ERCOT to provide Balancing Energy Service for resolving Congestion, the actuation for specific units under an ERCOT approved Special Protection System, or, if required, in declared emergencies as described in these Protocols.

As provided by a QSE to ERCOT: The provision of incremental or decremental energy dispatched from a specific Resource in emergency operations by Settlement Interval in Real Time to meet the balancing needs of the ERCOT System or in declared emergencies.

6.1.12 Zonal Out-of-Merit Energy (Zonal OOME) Service

As provided by ERCOT to QSEs: The deployment by ERCOT for the Settlement Interval of energy from a QSE's fleet of Resources, that may or may not have provided Resource-specific premium bids, and used by ERCOT when all other methods for resolving Congestion have failed or if required in declared emergencies as described in these Protocols.

As provided by a QSE to ERCOT: The provision of incremental or decremental energy Dispatched from a QSE's fleet of Resources in emergency operations by Settlement Interval in Real Time to meet the needs of the ERCOT System when all other methods for resolving Congestion have failed or in declared emergencies.

6.1.13 Emergency Interruptible Load Service (EILS)

Consistent with subsection (a) of P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Interruptible Load Service (EILS), EILS is defined as a special emergency service used during an Energy Emergency Alert (EEA) Level 2B or Level 3 to reduce Load and assist in maintaining or restoring ERCOT System frequency.

As provided by ERCOT to QSEs: A special emergency service used by ERCOT in EEA Level 2B prior to ERCOT instructing TDSPs to shed firm Load, or in EEA Level 3 if deployment in EEA Level 2B was not possible.

As provided by a QSE to ERCOT: The provision of capacity by Load Resources capable of reducing their electricity consumption during EEA Level 2B or EEA Level 3.

6.2 Providers of Ancillary Services

6.2.1 Ancillary Services Provided Solely by ERCOT

ERCOT is the sole provider of system-wide Balancing Energy Service; Generation Resource unit-specific Voltage Support Service (VSS), Black Start Service, Replacement Reserve Service, Zonal OOME Service, RMR Service, EILS (defined as a special emergency service), OOMC, and OOME Service to QSEs.

ERCOT will arrange Resources to provide system-wide VSS, Black Start, Zonal OOME, EILS and RMR Service from QSEs. ERCOT will direct Resources to provide OOMC or OOME in accordance with OOMC Service and OOME Service provisions of the Protocols.

6.2.2 Ancillary Services Provided in Part by ERCOT and in Part by Qualified Scheduling Entities

Each QSE may self-arrange its Obligation assigned by ERCOT for each of the following Ancillary Services: Regulation Up, Regulation Down, Responsive Reserve, and Non-Spinning Reserve. Any of the Ancillary Services that are not self-arranged will be procured as a service by ERCOT on behalf of the QSEs.

6.3 Responsibilities of ERCOT and Qualified Scheduling Entities

6.3.1 ERCOT Responsibilities

(1) ERCOT, through its Ancillary Services function, shall develop the Operating Day Ancillary Services Plan for the ERCOT System, and the Day Ahead Ancillary Service Obligation which will be assigned based on Load Ratio Share data, by LSE, aggregated to the QSE level. Unless otherwise provided in these Protocols, a QSE's allocation for Ancillary Service Obligation will be determined for each hour according to that LSE's Load Ratio Share computed by ERCOT. The LSE Ancillary Service allocation for the Day Ahead Ancillary Service Obligation shall be based on the hourly Load Ratio Share from the Initial Settlement data, for the Operating Day that is fourteen (14) days before the day in which the Obligation is being calculated, as defined in Section 9.2, Settlement Statements, for the same hour and day of the week multiplied by the quantity of the service in the Operating Day Ancillary Service Plan.

(2) ERCOT shall procure required Ancillary Services not self-arranged by QSEs.

(3) ERCOT accepts Ancillary Service bids only from QSEs.

(4) ERCOT shall allow the same capacity to be bid as multiple Ancillary Services types recognizing that this capacity may only be selected for one service.

(5) ERCOT shall ensure provision of Ancillary Services to all ERCOT System Market Participants in accordance with these Protocols.

(6) ERCOT shall not discriminate when obtaining Ancillary Services from QSEs submitting Ancillary Service bids. ERCOT shall not discriminate between Self-Arranged Ancillary Services and ERCOT-procured Ancillary Services when dispatching Ancillary Services.

(7) For AS that are not self-arranged, ERCOT shall procure any additional Resources ERCOT requires during the Day-Ahead Scheduling Process, the Adjustment Period process, or the Operating Period.

(8) ERCOT shall procure Resources that are used to provide Reliability Must-Run Service or Black Start Service through longer-term Agreements.

(9) Following submission of QSE self-arranged schedules, ERCOT will identify the remaining amount of Ancillary Services that must be acquired in order to complete ERCOT's Day-Ahead Ancillary Services Plan. Regulation Up, Regulation Down, Responsive, and Non-Spinning services will be procured by ERCOT on the timeline described in Section 4, Scheduling.

(10) ERCOT will not profit financially from the market. ERCOT will follow the Protocols with respect to the procurement of Ancillary Services and will not otherwise take actions regarding Ancillary Services with the intent to influence, set or control market prices.

(11) ERCOT will provide that Market Clearing Prices are posted on the Market Information System (MIS) in a timely manner as stated in Section 12.4.1, Scheduling Information, of these Protocols. ERCOT will monitor Market Clearing Prices for errors and will "flag" for further review questionable prices before posting, and make adjustments or notations in the posting if there are conditions that cause the price to be questionable. ERCOT may only correct the price consistent with these Protocols.

(12) ERCOT shall post the aggregated ERCOT AS Bid Stacks in accordance with Section 12.4.2, Ancillary Service Related Information of these Protocols.

(13) ERCOT will, through procurement processes specified in these Protocols, procure Ancillary Services as required and charge QSEs for those Ancillary Services in accordance with these Protocols.

(14) ERCOT will ensure ERCOT electric network reliability and adequacy and will afford the market a reasonable opportunity to supply reliability solutions.

(15) ERCOT will not substitute one type of Ancillary Service for another.

(16) ERCOT shall make reasonable efforts to minimize the use of OOMC, Zonal OOME, or contracted RMR Facilities. This includes entering into MRA Agreements with Resources selected through the planning process, pursuant to Section 6.5.9.2, to provide services to meet reliability requirements at lower total expected costs than would otherwise be provided by RMR Agreements.

(17) ERCOT will provide timely information to those Resource units providing OOMC and RMR Services as to the specific use of each unit dispatched.

6.3.2 Qualified Scheduling Entity Responsibilities

(1) Unless contracted otherwise, and with the exception of (a) Balancing Energy decremental bids, and (b) Balancing Energy Up bids for BES-Capable Non-Spinning Reserve Service (BESCNSRS) capacity as described in Section 4, Scheduling, Resources capable of providing Ancillary Services are not required to provide those Resources or to submit bids to ERCOT provided, however, Resources shall honor bids submitted to ERCOT for Ancillary Services under these Protocols and shall use reasonable efforts to provide Ancillary Services in accordance with applicable emergency procedures in these Protocols and in the Operating Guides.

(2) Ancillary Service providers shall provide and deploy, as directed by ERCOT, the Ancillary Service(s) that they have agreed to provide.

(3) QSEs may specify Self-Arranged Ancillary Services in accordance with the Day Ahead scheduling as described in Section 4.4, Day Ahead Scheduling Process.

[PIP106: Current design does not provide for DLC Profiles. When DLC Profiles are implemented add this item (4) to section 6.3.2]

(4) QSEs that have Direct Load Control (DLC) programs as described in Section 18.7.2, Other Load Profiling, will notify ERCOT immediately of any deployment of the program. This applies solely to QSEs using Load Profiling for Settlement.

6.4 Standards and Determination of the Control Area Requirements for Ancillary Services

6.4.1 Standards for Determining Ancillary Services Quantities

(1) ERCOT shall comply with the requirements for determination of Ancillary Service quantities as specified in these Protocols and the Operating Guides.

(2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the minimum quantity requirements for each Ancillary Service needed for reliability, including the percentage of Load acting as a Resource allowed to provide Responsive Reserve Service calculated on a monthly basis.

(3) ERCOT shall initially determine the percentage of Load acting as a Resource on a calendar month basis for the remainder of the current year allowed to provide Responsive Reserve Service within ninety (90) days after implementation of this Protocol revision.

(4) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements and the monthly percentage of Load acting as a Resource allowed to provide Responsive Reserve Service.

(5) If ERCOT determines a need for additional Ancillary Service Resources pursuant to these Protocols or the Operating Guides, after an Ancillary Services Plan for a specified day has been posted, ERCOT will inform the market by posting on the Market Information System, of ERCOT's intent to procure additional Ancillary Service Resources in accordance with Section 4.5.8, ERCOT Notice to Procure Additional Ancillary Services. ERCOT will post the reliability reason for the increase in service requirements.

(6) Once specified by ERCOT for an hourly interval, Ancillary Service quantity requirements may not be decreased.

(7) ERCOT shall instruct such that sufficient Resource capacity is on line, in appropriate locations, and available to ERCOT to meet the potential needs of the ERCOT System.

(8) ERCOT shall include in its AS plan sufficient capacity to automatically control frequency to meet NERC standards.

(9) ERCOT will post Engineering Studies on the MIS representing specific Ancillary Service requirements as described in Section 12, ERCOT Market Information System.

6.4.2 Determination of ERCOT Control Area Requirements

By the twentieth (20th) day of the current month, ERCOT will post a forecast of minimum Ancillary Services quantity requirements for the next calendar month.

Prior to 0600 of the Day Ahead, ERCOT will use the Day Ahead Load forecast and will develop an Ancillary Services Plan that identifies the amount of Ancillary Services necessary for each hour of the next day as specified in Section 4, Scheduling. The amount of Ancillary Services required may vary depending on ERCOT System conditions from hour to hour.

By 0600 of the Day Ahead, ERCOT will post an ERCOT System and zonal Load forecast for the next seven (7) days, by hour. ERCOT will notify each QSE of its allocated share of Ancillary Services for each hour for the next day, as specified in Section 4, Scheduling. ERCOT will make available to Market Participants any ERCOT area Load forecasts used in the determination of its ERCOT System and zonal forecasts.

ERCOT will determine the total required amount of each Ancillary Service using the Operating Guides and the following:

(1) Balancing Energy Service: ERCOT will estimate Balancing Energy needs based on the actual Load, the difference in forecasted Loads and Loads reported in bilateral schedules, deployed Regulation Service, and forecasted Congestion.

(2) Regulation Service: ERCOT will use its operational judgment and experience to determine the quantity of Regulation Up Service and Regulation Down Service procured. The quantity of Regulation Up Service may differ from the quantity of Regulation Down Service in any particular hour.

(3) Responsive Reserve Service: The requirement for Responsive Reserve Service is specified in the Operating Guides. Using ERCOT-approved procedures ERCOT may increase the quantity requirement based on its judgment of reliability conditions.

(4) Non-Spinning Reserve Service: ERCOT will use its operational judgment and experience to determine the quantity of Non-Spinning Reserve Service procured.

(5) Replacement Reserve Service: Replacement Reserve Service is procured from Generation Resource units planned to be Off-line and LaaRs that are available for interruption during the period of requirement. The QSE for a procured RPRS Resource must additionally make available to ERCOT via Balancing Energy Service bid(s) (i) for a Generation Resource, a quantity greater or equal to the High Sustainable Limit (if unavailable, the High Operating Limit) minus the Low Sustainable Limit (if unavailable, the Low Operating Limit) of the Generation Resource receiving the RPRS Dispatch Instruction in the Congestion Zone of the Generation Resource, and (ii) for a LaaR, a quantity equal to the amount of procured capacity from the LaaR in the Congestion Zone of the LaaR. ERCOT will consider the Generation Resource capacity On-line, based on Resource Plans, in its determination of Zonal Congestion and Local Congestion requirements. ERCOT will evaluate the need for Replacement Reserve Service necessary to correct for ERCOT total capacity insufficiency, Zonal Congestion, or Local Congestion. ERCOT shall determine the amount of RPRS to provide sufficient capacity in appropriate locations to provide ERCOT System security as specified in the Operating Guides, given ERCOT forecasted Load conditions as posted on the Market Information System.

(6) Voltage Support: ERCOT in coordination with the TDSPs shall conduct studies to determine the normally desired Voltage Profile for all Voltage Support busses in the ERCOT System and shall post all Voltage Profiles on the Market Information System. ERCOT may temporarily modify its requirements based on Current System Conditions. ERCOT shall determine the amount of Voltage Support Service needed to provide sufficient reactive capacity in appropriate locations to provide ERCOT System security as specified in the Operating Guides.

(7) Black Start Service: 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 policy.

6.5 Ancillary Services Selection and Requirements

Providers of Ancillary Services and special emergency services shall meet the general requirements specified in Section 6.5.1, General Technical Requirements, below as well as the requirements of the specific Ancillary Service or special emergency service being provided, as described herein.

6.5.1 General Technical Requirements

Providers of Ancillary Services shall meet the following general requirements.

6.5.1.1 Requirement for Operating Period Data for System Reliability and Ancillary Service Provision

Operating Period data will be used by ERCOT to monitor the reliability of the ERCOT System in Real Time, monitor compliance with Ancillary Service Obligations, perform historical analysis, and predict the short-term reliability of the ERCOT System using network analysis software. Each Transmission and/or Distribution Service Provider (TDSP), at its own expense, may obtain such Operating Period data from ERCOT or from Qualified Scheduling Entities (QSEs).

(1) A QSE representing a Generation Entity that has Generation Resources connected to a TDSP shall provide the following Real Time data to ERCOT for each individual generating unit at a Generation Resource plant location and ERCOT will make the data available to the Generation Resource's host TDSP (at TDSP expense):

(a) Gross and net real power, or

Gross real power at the generator terminal and unit auxiliary Load real power, or

Net real power at the ERCOT Polled Settlement (EPS) Meter and unit auxiliary Load real power.

(b) Gross reactive power at the generator terminal

(c) Status of switching devices in the plant switchyard not monitored by the TDSP affecting flows on the ERCOT System;

(d) Frequency Bias of Portfolio Generation Resources under QSE operation;

(e) Any data mutually agreed by ERCOT and the QSE to adequately manage system reliability and monitor Ancillary Service Obligations;

(f) Generator breaker status;

(g) High Operating Limit (HOL); and

(h) Low Operating Limit (LOL).

[PRR590: Add items (i) and (j) upon system implementation:]

(i) Automatic Generation Control (AGC) status; and

(j) Ramp rate.

[PRR307: Revise Section 6.5.1.1(1) and 6.5.1.1(1)(f) as follows when system change implemented.]

(1) A QSE representing a Generation Entity or a Competitive Retailer that has Resources connected to a TDSP shall provide the following Real Time data to ERCOT for each individual generating unit or Load acting as a Resource (LaaR) capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and that immediately respond proportionally to frequency changes (similar to generator governor action) at a Resource plant location and ERCOT will make the data available to the Resource's host TDSP (at TDSP expense):

(f) Resource breaker status;

[PRR590: Add paragraph (2) and renumber subsequent paragraphs upon system implementation:]

(2) A QSE representing Uncontrollable Renewable Resources is exempt from the requirements of items (1) (i) and (j) above.

(2) Any QSE providing Responsive Reserve and/or Regulation must provide for communications equipment to receive ERCOT telemetered control deployments of service power.

(3) Any QSE providing Regulation Service must provide appropriate Real Time feedback signals to report the control actions allocated to the QSEs Resources.

(4) Any QSE that represents a provider of Responsive Reserve, Non-Spinning Reserve, or Replacement Reserve using interruptible LaaR shall provide separate telemetry of the real power consumption of each interruptible Load providing the above Ancillary Services, the LaaR response to Dispatch Instructions for each LaaR, and the status of the breaker controlling that interruptible Load. If interruptible Load is used as a Responsive Reserve Resource, the status of the high-set under frequency relay will also be telemetered.

(5) Any QSE that represents a qualified provider of Balancing Up Load (BUL) need not provide telemetry, but rather shall provide an estimate in Real Time representing the real power interrupted in response to the deployment of Balancing Up Load.

(6) Real Time data for reliability purposes must be accurate to within three-percent (3%). This telemetry may be provided from relaying accuracy instrumentation transformers.

(7) A Wind-powered Generation Resource (WGR) Entity shall provide the following site-specific meteorological information to ERCOT through its QSE selected for this purpose. The WGR shall be responsible for any associated compliance metrics. ERCOT shall

establish procedures specifying the accuracy requirements of WGR meteorological information telemetry:

(a) Wind speed;

(b) Wind direction;

(c) Temperature; and

(d) Barometric pressure.

[PRR590: Insert paragraph (7) and renumber accordingly, upon system implementation]

(7) A QSE representing a combined cycle plant may aggregate the AGC and ramp rate Supervisory Control and Data Acquisition (SCADA) points for the individual units at a plant location into two distinct SCADA points (AGC and ramp rate) if the plant is configured to operate as such, i.e. gas turbine(s) and steam turbine(s) are controlled in aggregate from an AGC perspective.

6.5.2 Balancing Energy Service

The Balancing Energy Service bids shall consist of Balancing Energy Service Up, Balancing Energy Service Down, BES-Capable Non-Spinning Reserve Service (BESCNSRS), and BUL bids. All Balancing Energy Service provider bids must be entered by the close of the Adjustment Period for the effective Operating Hour and shall become an Obligation at the close of the Adjustment Period. However, Balancing Energy Service provider bids may be withdrawn at any time prior to the close of the Adjustment Period. The portion of a QSE's Balancing Energy Service Up bid deployable in one (1) interval that may be provided by Off-line Generation Resources shall be limited to no more than the aggregate of qualified output amounts from Quick Start Units which have been demonstrated via the qualification testing process described in the Operating Guides. The QSE may utilize any remaining capacity from Quick Start Units in subsequent intervals once the Quick Start Units are On-line.

(1) Balancing Energy Service bids must specify Congestion Zone, the type of bid, either a Resource or a BUL used to deploy the service, a ramp rate and service time period.

[PRR675: Replace paragraph (1) above with the following upon system implementation:]

(1) Balancing Energy Service bids must specify Congestion Zone, the type of bid, either a Resource or a BUL used to deploy the service, a ramp rate or ramp rate curve, and service time period.

(a) For Balancing Energy Service Up and Balancing Energy Service Down, the bid curve consists of monotonically increasing ordered pairs of dollars per megawatt hour and cumulative megawatts ($/MWh, MW).

(b) For BUL, the bids consist of blocks in dollars per megawatt hour and megawatts ($/MWh, MW). If the full block cannot be deployed the bid will be bypassed.

(2) QSEs shall provide Balancing Energy Service Down bids prior to the close of the Adjustment Period equal to or greater than the requirement according to the amounts set forth for the QSE in Section 4.5.2, Receipt of QSE's Balancing Energy Bid Curves.

(3) ERCOT shall place all bids received for Balancing Energy Service Up and BUL in order from lowest bid price to highest bid price. This combination shall be the Balancing Energy Service Up Bid Stack. ERCOT will determine the total amount of energy bid in the stack available in sixty (60) minutes.

(4) ERCOT will determine the required amount of Balancing Energy Service such that Regulation Service Up (RGSU) energy and Regulation Service Down (RGSD) energy is provided in each Settlement Interval.

(5) ERCOT will plan to deploy Balancing Energy Service in each Settlement Interval in a manner that will minimize total net energy from Regulation Service (RGS).

(6) The Balancing Energy Service deployment will be in megawatts. The Balancing Energy Obligation shall be the power requested integrated over the interval.

(7) ERCOT may deploy Balancing Energy Service only in the Operating Period. ERCOT's selection of energy from Resources for deployment shall be based on the price Merit Order of bids received and bid ramp rate and not on the expected Market Clearing Price for Energy (MCPE). The ERCOT System Operator making Balancing Energy Service decisions shall not have access to the individual Balancing Energy Service bid prices or the expected MCPE.

(8) If the Balancing Energy Service Up Bid Stack does not overlap with the Balancing Energy Service Down Bid Stack, and ERCOT is using Balancing Energy Service Up and needs a lesser amount of Balancing Energy, ERCOT must first recall any Balancing Energy Service Up prior to deploying any Balancing Energy Service Down, unless resolving Local Congestion.

(9) If the Balancing Energy Service Up bid prices are lower than Balancing Energy Service Down bid prices, also known as overlap, and deployment required of Balancing Energy Service would result in an MCPE within the overlap then, the Balancing Energy Service Up and Balancing Energy Service Down or a portion of each are deployed, unless resolving Local Congestion.

(10) If ERCOT is using Balancing Energy Service Down and needs a greater amount of Balancing Energy, ERCOT must first recall any Balancing Energy Service Down prior to deploying any Balancing Energy Service Up, subject to this subsection.

(11) If ERCOT is using Balancing Energy Service Up and needs a lesser amount of Balancing Energy Service, ERCOT must first recall any Balancing Energy Service Up prior to deploying any Balancing Energy Service Down, subject to this subsection.

(12) ERCOT shall not deploy Balancing Energy Service Up and Down in the same Settlement Interval in the same Congestion Zone, unless clearing an overlap in the Balancing Energy Service Up and Balancing Energy Service Down bid prices, or solving Local Congestion.

(13) ERCOT shall provide ten (10) minutes notice to the QSEs providing Balancing Energy Service Up or Balancing Energy Service Down to change deployment via the Messaging System.

[PRR601, PRR803: Replace paragraph (13) above with the following upon system implementation:]

(13) ERCOT shall provide notice via the Messaging System to the QSE providing Balancing Energy Service Up or Balancing Energy Service Down to change deployment three (3) minutes prior to the start of the time at which the Resource must begin to ramp up or down.

(14) ERCOT shall provide Notice electronically via the Messaging System to each QSE with the number of megawatts expected to be delivered as a result of Balancing Energy Service Dispatch Instructions. The Messaging System will identify requests for BUL.

(15) LaaRs and providing Balancing Energy Service must be capable of responding to ERCOT Dispatch Instructions in a similar manner to Generation Resources. BUL is not considered to be a LaaR.

(16) The deployment of power shall be constrained by the bidders' specified ramp rate except during Energy Emergency Alert (EEA) operations.

(17) With the exception of BUL and LaaR providing Balancing Energy Service Up, QSEs are expected to comply with Balancing Energy Service Dispatch Instructions by ramping at a constant ramp rate, as calculated in paragraph (18) below, during a fixed ramp period starting five (5) minutes prior to the start of the target service interval and ending five (5) minutes after the start of the target service interval.

[PRR601, PRR803: Replace paragraph (17) above with the following upon system implementation:]

(17) With the exception of BUL and LaaRs providing Balancing Energy Service Up, QSEs are expected to comply with Balancing Energy Service Dispatch Instructions by ramping at a constant ramp rate, as calculated in paragraph (18) below, during a fixed ramp period starting seven (7) minutes prior to the start of the Settlement Interval covered by the Dispatch Instruction and ending seven (7) minutes after the start of the Settlement Interval covered by the Dispatch Instruction.

(18) With the exception of BUL and LaaR providing Balancing Energy Service Up, Balancing Energy Service Dispatch Instructions, inclusive of recall instructions, by ERCOT to any QSE are constrained by the amount of energy that the QSE can deploy within the ten (10) minute ramp period at the ramp rates that are communicated to ERCOT in the QSE's bid. Expressed in MW/Min, the ramp rates serve as the basis for calculating the maximum change in the amount of energy that the QSE can deploy from one (1) fifteen (15) minute Settlement Interval to the next. In calculating these energy amounts, ERCOT will calculate the upper and lower limits of the Balancing Energy Service Dispatch Instruction of the target Settlement Interval as follows:

Direction of Deployment in Prior Settlement Interval	**Limits to P_1**
$P_0 > 0$	$P_0 + 10 \times RRU$
$P_0 > 0$	$P_0 - \text{Min}(P_0 / RRU, 10) \times RRU$ $\underline{- [10 - \text{Min}(P_0 / RRU, 10)] \times RRD}$
$P_0 < 0$	$P_0 + \text{Min}(-P_0 / RRD, 10) \times RRD$ $\underline{+ [10 - \text{Min}(-P_0 / RRD, 10)] \times RRU}$
$P_0 < 0$	$P_0 - 10 \times RRD$

Where:

P_0	MW amount of Balancing Energy Service deployed by ERCOT in the previous Settlement Interval.
P_1	MW amount of Balancing Energy Service deployed by ERCOT in the target Settlement Interval.
RRU	bid ramp rate (always positive) in MW/min associated with the QSE's Balancing Up bid for the target interval. If RRU is not available for the target interval, ERCOT will use the most recent value of the QSE's RRU.
RRD	bid ramp rate (always positive) in MW/min associated with the QSE's Balancing Down bid for the target interval. If RRD is not available for the target interval, ERCOT will use the most recent value of the QSE's RRD.
$P_1 > P_0$	indicates a deployment of more energy in the up direction and/or less energy in the down direction from the previous Settlement Interval to the target Settlement Interval.
$P_1 < P_0$	indicates a deployment of less energy in the up direction and/or more energy in the down direction from the previous Settlement Interval to the target Settlement Interval.

ERCOT will honor the limits to P_1, as calculated above, in determining P_1.

ERCOT will calculate the constant ramp rate for the P_1 deployment as $[P_1 - P_0]/10$.

For settlement and instructed deviation purposes, the P_1 instruction along with the constant ramp rate will be used in determining the energy deployed during the ramp period and corresponding previous and target Settlement Intervals.

[PRR601, PRR803: Replace paragraph (18) above with the following upon system implementation:]

(18) With the exception of BUL and LaaRs providing Balancing Energy Service Up, Balancing Energy Service Dispatch Instructions, inclusive of recall instructions, by ERCOT to any QSE are constrained by the amount of energy that the QSE's Resource can deploy within the fourteen (14) minute ramp period at the ramp rates that are communicated to ERCOT in the QSE's bid. Expressed in MW/Min, the ramp rates serve as the basis for calculating the maximum change in the amount of energy that the QSE can deploy from one (1) fifteen (15) minute Settlement Interval to the next. In calculating these energy amounts, ERCOT will calculate the upper and lower limits of the Balancing Energy Service Dispatch instruction of the target Settlement Interval as follows:

Direction of Deployment in Prior Settlement Interval	**Limits to P_1**
$P_0 > 0$ and $P_1 > P_0$	$P_0 + 14 \times RRU$
$P_0 > 0$ and $P_1 < P_0$	**P_0 – MIN (P_0 / RRU, 14) x RRU** **– [14 – Min (P_0 / RRU, 14)] x RRD**
$P_0 < 0$ and $P_1 > P_0$	**P_0 + MIN (-P_0 / RRD, 14) x RRD** **+ [14 – Min (-P_0 / RRD, 14)] x RRU**
$P_0 < 0$ and $P_1 < P_0$	$P_0 - 14 \times RRD$

Where:

P_0 MW amount of Balancing Energy Service deployed by ERCOT in the previous Settlement Interval.

P_1 MW amount of Balancing Energy Service deployed by ERCOT in the target Settlement Interval.

RRU bid ramp rate (always positive) in MW/min associated with the QSE's Balancing Up bid for the target interval. If RRU is not available for the target interval, ERCOT will use the most recent value of the QSE's RRU.

RRD bid ramp rate (always positive) in MW/min associated with the QSE's Balancing Down bid for the target interval. If RRD is not available for the target interval, ERCOT will use the most recent value of the QSE's RRD.

$P_1 > P_0$ indicates a deployment of more energy in the up direction and/or less energy in the down direction from the previous Settlement Interval to the target Settlement Interval.

$P_1 < P_0$ indicates a deployment of less energy in the up direction and/or more energy in the down direction from the previous Settlement Interval to the target Settlement Interval.

ERCOT will honor the limits to P_1, as calculated above, in determining P_1.

ERCOT will calculate the constant ramp rate for the P_1 deployment as $[P_1\text{-}P_0]/14$.

For settlement and instructed deviation purposes, the P_1 instruction along with the constant ramp rate will be used in determining the energy deployed during the ramp period and corresponding previous and target Settlement Intervals.

(19) The QSE's instructed deviation will include the expected energy calculated using the constant ramp rate, as calculated in paragraph (18) above, during the ten (10) minute ramp period when complying with an ERCOT Balancing Energy Service Dispatch Instruction.

[PRR601, PRR803: Replace paragraph (19) above with the following upon system implementation:]

(19) The QSE's instructed deviation will include the expected energy calculated using the constant ramp rate, as calculated in paragraph (18) above, during the fourteen (14) minute ramp period when complying with an ERCOT Balancing Energy Service Dispatch Instruction.

(20) ERCOT may also use LaaRs qualified to provide Regulation, Responsive Reserve, Non-Spinning Reserve, or Replacement Reserve Services to provide Balancing Energy under the Out of Merit Energy (OOME) instructions and pricing structure. ERCOT shall not use Loads qualified to provide only BUL Service under the OOME instructions and pricing structure.

(21) The minimum number of megawatts of Balancing Energy Service that may be offered to ERCOT is one (1) MW.

(22) Should the Bid Stack for Balancing Energy Down Service be exhausted, ERCOT may send Dispatch Instructions to select Resources for OOME Service which causes the Resources to go Off-line.

(23) ERCOT shall automatically limit each QSE's zonal Balancing Energy Service Up bids by the sum of the High Sustainable Limits (HSLs) from the Resource Plan for the

Generation Resources, by zone, less the zonal schedule for the QSE's Resources. Any reduction to the Balancing Energy Service Up bid shall be implemented starting with the highest priced bids.

(24) ERCOT shall automatically limit each QSE's zonal Balancing Energy Service Down bids by the zonal schedule for the QSE's Resources less the sum of the Low Sustainable Limits (LSLs) from the Resource Plan for the Generation Resources, by zone. Any reduction to the Balancing Energy Service Down bid shall be to the lowest cost bids.

[PRR675: Add the language below upon system implementation:]

(25) QSEs may submit Balancing Energy Service Up and Down bids with multiple portfolio ramp rates.

6.5.2.1 Balancing Energy Service Bids from Bilateral Contracts

Market Participants may enter into bilateral contracts, including entitlements to Capacity Auction Products, which allow one QSE rights to submit Balancing Energy bids (bidding QSE) to ERCOT and identify another QSE as the Balancing Energy Service provider for purposes of bid deployment (deploying QSE). Subject to the provisions in 6.5.2, Balancing Energy Service bids may be submitted to ERCOT by a bidding QSE who will identify the deploying QSE associated with the bid curve. ERCOT will send the Balancing Energy Service Dispatch Instructions associated with the bids to the deploying QSE.

(1) Two QSE's may jointly apply to ERCOT for approval that both QSE's intend to provide Balancing Energy Service in accordance with this Section 6.5.2.1. The QSEs shall submit to ERCOT a summary of the Balancing Energy Service, identifying (a) the bidding QSE, (b) the QSE who will be receiving the Balancing Service Dispatch Instructions from ERCOT (deploying QSE), (c) the term of the service and (d) the Congestion Zone(s) in which the energy will be delivered.

(2) The deploying QSE must be a qualified Ancillary Service provider for Balancing Energy Service.

(3) The bidding QSE may submit separate bid curves for Balancing Energy Service Up and Balancing Service Down for each zone for each bilateral Agreement, which provides for such service.

(4) ERCOT will provide Notice via the Messaging System to the bidding QSE and the deploying QSE of the awards for Balancing Energy Service identifying the bidding QSE and the deploying QSE.

(5) ERCOT will notify the bidding QSE and the deploying QSE of the deploying QSE's instructed amount of Balancing Energy Service in accordance with Section 6.7.1.1.

(6) ERCOT will settle with the deploying QSE in accordance with Section 6.8.1.12.

6.5.3 Regulation Service (RGS)

(1) The QSE's control system must be capable of receiving digital control signals from ERCOT's control 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, consistent with established NERC and ERCOT operating criteria.

(2) Any QSE providing RGS must provide for communications equipment to receive telemetered control deployments of power from ERCOT.

(3) QSEs must demonstrate to ERCOT that they have the capability to switch control to constant frequency operation as specified in the Operating Guides using telemetry at the QSE's control center. ERCOT authorized operations of the QSE's regulation control system on constant frequency will be considered a Dispatch Instruction to deviate from schedule energy.

(4) QSEs providing RGS will be required to provide a feedback signal meeting the requirements of ERCOT.

(5) The Resource providing RGS must be capable of delivering the full amount of regulating capacity offered to ERCOT within ten (10) minutes.

(6) Load Resources providing RGS must be capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and immediately responding proportionally to frequency changes (similar to generator governor action).

(7) The minimum amount of RGS that may be offered to ERCOT is one (1) MW.

(8) QSE's bids will be in accordance with Section 4, Scheduling.

(9) Regulation instructions will be included in a QSE's Schedule Control Error (SCE) calculation as instructed deviations.

(10) Each Resource providing RGS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification, Testing and Performance Standards, of these Protocols.

(11) Resources providing RGS must have their governors or automatic systems changing Load responding to frequency in service.

(12) RGS is deployed proportionately to all providers.

(13) Resources providing RGS must have sufficient qualified Generation Resources that will be online and able to respond in the Operating Hour for which they have been selected to provide the Ancillary Service.

6.5.4 Responsive Reserve Service

(1) Responsive Reserve Service (RRS) may be provided by:

(a) Unloaded Generation Resources that are On-line;

(b) Resources controlled by high-set under-frequency relays;

(c) Hydro Responsive Reserves;

(d) From DC Tie response that stops frequency decay or; and

(e) From Load Resources capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and that immediately respond proportionally to frequency changes (similar to generator governor action).

The minimum amount of RRS provided by Generation Resources and Load Resources capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and that immediately respond proportionally to frequency changes (similar to generator governor action) shall be as specified in the Operating Guides. QSE's Resources providing RRS must be On-line and capable of ramping to the awarded output level within ten (10) minutes of the notice to deploy energy, must be immediately responsive to system frequency, and must be able to maintain the scheduled level for the period of service commitment. The amount of RRS on an individual Generation Resource may be further limited by requirements of the Operating Guides.

(2) A QSE's Load acting as a Resource must be loaded and capable of unloading the scheduled amount of RRS within ten (10) minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays as specified by the Operating Guides.

(3) Any QSE providing RRS must provide communications equipment to receive ERCOT telemetered control deployments of power.

(4) Generation Resources providing RRS must have their governors in service.

(5) Interruptible Loads acting as a Resource providing RRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay.

(6) The minimum amount of RRS that may be offered to ERCOT is one (1) MW.

(7) QSEs that provide the Resource for Responsive Reserve Service must ensure that Resources providing the service must be able to respond in the Operating Hour for which

they have been selected to provide the RRS. Each Generation Resource and Load acting as a Resource and providing RRS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification, Testing, and Performance Standards of these Protocols.

(8) The amount of Resources on high-set under-frequency relays providing RRS will be limited to fifty percent (50 %) of the total ERCOT RRS requirement. 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 to be deployed as prescribed in Section 6.4.1, Standards for Determining Ancillary Services Quantities.

(9) The amount of RRS that a QSE can self-arrange using Load acting as a Resource is limited to the lower of:

(a) the fifty percent (50%) limit set by these Protocols; or,

(b) the limit established by ERCOT. However, a QSE may bid additional Load acting as a Resource above the percentage limitation established by ERCOT for sale of RRS to other Market Participants. The total amount of Responsive Reserve Service using Load acting as a Resource procured by ERCOT is also limited to the lesser of the fifty percent (50%) limit or the limit established by ERCOT.

(10) QSE bids for RRS will be in accordance with Section 4, Scheduling.

(11) A Load acting as a Resource has the option to request a Load bid to be deployed only as a complete block. To the extent that ERCOT deploys a bid by a Load acting as a Resource that has chosen a block deployment option, ERCOT shall either deploy the entire bid or, if only partial deployment is possible, skip the bid by the Load acting as a Resource and proceed to deploy the next available bid.

(12) The amount of RRS that a QSE can self-arrange using Load acting as a Resource is limited to the percentage amount of total RRS that the LaaR can provide as specified by ERCOT. However, a QSE may bid additional Load acting as a Resource into the ERCOT RRS Ancillary Service market.

(13) LaaRs providing the RRS requested shall return to their committed operating level for providing RRS as soon as practical considering process constraints. For LaaRs unable to return to their committed operating level within three (3) hours, their QSE may schedule the quantity of deficient Responsive Reserve Service Capacity from other uncommitted Generation or LaaR Resource(s) to fulfill their RRS obligation.

(14) RRS bids from QSEs may include contributions from combined cycle Resources in Aggregated Units meeting the criteria in Section 6.8.2.4, Aggregating Units. Thus, to determine if a combined cycle Aggregated Unit is capable of performing its RRS Obligation, all Resources On-line in the Aggregated Unit will be measured as on an aggregate capacity basis and will be calculated from the lower of the High Sustainable

Limits specified in the Resource Plan or through telemetry, or the seasonal tested Net Dependable Capability.

6.5.5 Non-Spinning Reserve Service (NSRS)

(1) A QSE supplying 30-Minute Non-Spinning Reserve Service (30MNSRS) shall not submit Balancing Energy Service bids representing that capacity.

(2) A QSE having Resources supplying BESCNSRS shall have those Resources qualified and pre-approved by ERCOT according to a procedure described in the Operating Guides. On-line Resources qualified for BESCNSRS shall be separated into a separate virtual resource using generation meter splitting as described in Section 10.3.2.1, Generation Meter Splitting. ERCOT shall establish a procedure for qualifying and including these BES-Capable On-line Non-Spinning Reserve Service (On-line BESCNSRS) virtual Resources. ERCOT may provide one hundred twenty (120)-day provisional approval pending qualification according to Operating Guides requirements.

(3) ERCOT shall create an operating procedure to establish scheduling requirements for BESCNSRS.

(4) During the Adjustment Period, a QSE shall:

(a) Submit Balancing Energy bids for BESCNSRS capacity consistent with Section 4.5.2, Receipt of QSE's Balancing Energy Bid Curves, and

(b) Adjust their Ancillary Service schedule to represent only those QSE Resources providing 30MNSRS according to ERCOT procedure.

(5) Loads providing Non-Spinning Reserve Service (NSRS) must provide a telemetered output signal, including breaker status.

(6) The minimum amount of NSRS that may be offered to ERCOT is one (1) MW.

(7) QSE bids for NSRS will be submitted in accordance with Section 4, Scheduling.

(8) Each Generation Resource and LaaR providing NSRS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification Testing and Performance Standards.

(9) QSEs using Loads to provide NSRS must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resource to provide NSRS.

(10) Resources providing NSRS must be able to respond in the hours for which they have been scheduled to provide the Ancillary Service.

6.5.6 Replacement Reserve Service

(1) Replacement Reserve Service (RPRS) is provided by Resources that may otherwise be unavailable to ERCOT in the hours that ERCOT requests RPRS. These Resources may include Generation Resources that are expected to be Off-line in the requested hours and Loads acting as a Resource (LaaR) that are declared to be available in the Resource Plan but are not committed to any service Obligation.

(2) Resources providing RPRS must provide a telemetered output signal, including breaker status.

(3) The minimum amount of RPRS that may be offered to ERCOT is one (1) MW.

(4) Resources eligible to bid must meet additional technical requirements specified in Operating Guides.

(5) There may only be one RPRS bid from any given Resource.

(6) Generation Resource and Loads acting as a Resource accepted for RPRS must be able to respond in the hours for which they have been selected to provide the Ancillary Service.

(7) QSEs using Loads to provide RPRS must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resources to provide RPRS.

(8) Each Generation Resource and Load acting as a Resource providing RPRS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification, Testing and Performance Standards. QSEs must comply with their Balanced Schedule despite any generation provided by the RPRS unit. For example, the QSE supplying RPRS must adjust other Resources to accommodate the minimum operating output of the RPRS Resource selected by ERCOT in order to comply with their Balanced Schedule and Dispatch Instructions.

(9) QSE bids for RPRS will be in accordance with Section 4, Scheduling.

(10) RPRS may not be self-arranged by the QSE.

(11) For RPRS procurements due to Local Congestion, on or before the second (2^{nd}) Business Day after each Operating Day, ERCOT will post on the MIS, for such Operating Day:

(a) Each Resource receiving an RPRS Dispatch Instruction;

(b) Intervals for which each Resource received an RPRS Dispatch Instruction;

(c) The Low Sustainable Limit for each Resource receiving an RPRS Dispatch Instruction; and

(d) The binding transmission constraint (contingency and/or overloaded element(s)) causing the RPRS deployment.

(12) For RPRS procurements due to Zonal Congestion, on or before the second (2nd) Business Day after each Operating Day, ERCOT will post on the MIS, for such Operating Day:

(a) The amount of RPRS procured by zone; and

(b) The Market Clearing Price for Capacity (MCPC) by zone.

(13) On or before the second (2nd) Business Day after each Operating Day, ERCOT will post on the MIS, for such Operating Day, the total amount of RPRS procured by hour for;

(a) Local Congestion;

(b) Zonal Congestion; and

(c) System capacity.

6.5.7 Voltage Support Service

All Generation Resources (including self-serve generating units) that have a gross generating unit rating greater than twenty (20) MVA or those units connected to the same transmission bus that have gross generating unit ratings aggregating to greater than twenty (20) MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

6.5.7.1 Generation Resources Required to Provide VSS Installed Reactive Capability

(1) Generation Resources required to provide VSS must be capable of producing a defined quantity of Reactive Power at rated capability (MW) to maintain a Voltage Profile established by ERCOT. This quantity of Reactive Power is the Unit Reactive Limit (URL).

(2) Generation Resources required to provide VSS except as noted below in items (3) or (4), shall have and maintain a URL which has an over-excited (lagging) power factor capability of ninety-five hundredths (0.95) or less and an under-excited (leading) power factor capability of ninety-five hundredths (0.95) or less, both determined at the generating unit's maximum net power to be supplied to the transmission grid and at the transmission system Voltage Profile established by ERCOT, and both measured at the point of interconnection to the TDSP.

(3) 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 URL as stated above, will be required to maintain a URL that is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and criteria as described in the Operating Guides.

(4) 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 URL as stated above, will be required to maintain a URL that is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and criteria described in the Operating Guides.

(5) Upon request to, and with the approval of ERCOT, multiple generating units connected to the same transmission bus may be treated as a single generating unit for the purposes of these URL requirements only.

(6) Upon submission by a Generation Resource required to provide VSS to ERCOT of a specific proposal for requirements to substitute for these URL requirements, ERCOT shall either approve such alternative requirements or provide the submitter an explanation of its objections to the proposal. Alternative requirements may include supplying additional static and/or dynamic Reactive Power capability as necessary to meet the area's Reactive Power requirements.

(7) An induction generator may elect to make a contribution in aide of construction in lieu of meeting the installed capacity VSS requirements contained herein. In order to comply with the VSS requirements under this paragraph (7), the generator must make payment to the interconnecting TDSP under its generation Interconnection Agreement in a manner similar to that used to collect payments for the direct assignment of interconnection Facilities under applicable Public Utility Commission of Texas (PUCT) rules. The level of payment shall reflect the cost to the TDSP of procuring, installing, operating, and maintaining any Reactive Power equipment required to replace the Reactive Power capability that otherwise would be necessary for the interconnection of the generator. In order for this paragraph (7) to be effective for VSS compliance, the TDSP shall certify to ERCOT that the induction generator has complied with these requirements.

(8) For Generation Resources required to provide VSS, no unit equipment replacement or modification shall reduce the capability of the unit below the requirements to be met by that unit prior to the replacement/modification, unless specifically approved by ERCOT.

(9) Generation Resources required to provide VSS shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT (conveyed by way of their QSE) unless equipment damage is imminent.

6.5.7.2 QSE Responsibilities

(1) QSE Generation Resources required to provide VSS are expected to have and maintain Reactive Power capability at least equal to the Reactive Power capability requirements specified in these Protocols and the Operating Guides.

(2) Each QSE's Generation Resource providing VSS is expected to be compliant with the Operating Guides for response to transient voltage disturbance.

(3) Each Generation Resource providing VSS must meet technical requirements specified in Section 6.10, Ancillary Service Qualification, Testing and Performance Standards.

(4) Each QSE's Generation Resource providing VSS shall operate with the unit's Automatic Voltage Regulator (AVR) set to regulate generator terminal voltage in the voltage control mode unless specifically directed to operate in manual mode by ERCOT, or when the unit is going On- or Off- line. If the QSE changes the mode, other than under ERCOT direction, then the QSE shall promptly inform ERCOT. Any QSE-controlled power system stabilizers will be kept in service unless specifically permitted to operate otherwise by ERCOT. QSEs' control centers will monitor the status of their regulators and stabilizers, and shall report abnormal status changes to ERCOT.

(5) QSEs shall meet, within established tolerances, and respond to changes in the Voltage Profile established by ERCOT subject to the stated QSE Reactive Power and actual power operating characteristic limits and voltage limits.

(6) The reactive capability required must be maintained at all times the plant is On-line.

(7) QSE shall advise ERCOT Operations whenever their Generation Resources are not operating at a power factor level as specified in the Operating Guides. Upon such notice, ERCOT Operations, in conjunction with the appropriate TSP, shall investigate the situation with the goal of restoring the reported unit's operation to within the specified power factor range. Actions that ERCOT may take include the addition or removal of transmission reactive devices to/from service or a request to another Generator Resource within electrical proximity for the production of leading or lagging VARS (as appropriate) so as to equitably share the need for voltage support among Generation Resources. Requests arising within the context of this subsection may not result in the operation of a Generation Resource outside of the specified reactive operating range. Accordingly, Generation Resources are expected to voluntarily comply with these requests. Nothing in this subsection is meant to supersede ERCOT's Dispatch authority in the event of emergency operations.

6.5.7.3 ERCOT Responsibilities

(1) ERCOT, in coordination with the TDSPs, shall establish, and update as necessary, Voltage Profiles at points of interconnection of Generation Resources required to provide VSS to maintain system voltages within established limits.

(2) ERCOT shall communicate to the QSE and the TDSPs the desired voltage at the point of generation interconnection by providing Voltage Profiles.

(3) ERCOT, in coordination with the TDSPs, 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.

(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 TDSPs of any alternative requirements it approves pursuant to Section 5.2.1, Standards and Practices.

6.5.8 Black Start Service

(1) Providers of Black Start Service shall meet the requirements specified in NERC policy and Operating Guides.

(2) Each Resource providing Black Start Service must meet technical requirements specified in Section 6.10, Ancillary Service Qualification, Testing and Performance Standards.

(3) Beginning in 2009, ERCOT will request bids from Generation Resource Entities for the provision of Black Start Service. Such bids shall be due on or before June 1 of each two (2) year period. Bids will be evaluated based on evaluation criteria attached as an appendix to the request for bids and contracted by December 31 for the following two (2) year period. ERCOT shall ensure Black Start Services are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a total or partial system blackout.

(4) ERCOT shall schedule random testing or simulation, or both, to verify Black Start Service is operable according to the ERCOT System restoration plan. Testing and verification will be in accordance with established qualification criteria.

(5) QSEs representing Generation Resources contracting for Black Start Services shall participate in training and restoration drills coordinated by ERCOT.

(6) ERCOT shall periodically conduct system restoration seminars for all TDSPs, QSEs, Generation Entities and other Market Participants.

6.5.9 Reliability Must-Run Service

(1) Upon receiving Notice from a Generation Entity as described in Protocols Subsection 6.5.9.1, Application and Approval of RMR Agreements, ERCOT may enter into RMR Agreements and begin procurement of RMR Service according to the provisions of this section.

(2) Before entering into an RMR Agreement, ERCOT shall assess alternatives to the proposed RMR Agreement. The list of alternatives ERCOT should consider include (as reasonable for each type of reliability concern identified):

a) Redispatch/reconfiguration through operator instruction;

b) Remedial Action Plans;

c) Special protection schemes initiated on unit trips or transmission outages; and

d) Load response alternatives once a suitable Load response service is defined and available.

(3) ERCOT shall reasonably attempt to minimize the use of RMR Facilities. ERCOT shall have the right to Dispatch an RMR Unit at any time for transmission reliability. ERCOT will Dispatch the unit as early as possible once conditions are identified that require the use of the RMR Unit, as defined in Section 4, Scheduling and the RMR Agreement.

(4) Each RMR Unit must meet technical requirements specified in Section 6.10 Ancillary Services Qualification, Testing and Performance Standards.

(5) RMR Service is a contracted service between Generation Entities and ERCOT. The term of any RMR Agreement shall not exceed twelve (12) months except where a Generation Entity must make a significant capital expenditure to meet environmental regulations or to ensure availability in order to continue operating the unit so as to make an RMR Agreement in excess of twelve (12) months appropriate, in ERCOT's opinion and the ERCOT Board has approved a multi-year agreement. The term of a multi-year RMR Agreement shall reflect the RMR Replacement Option determined in Section 6.5.9.1, Initiation and Approval of RMR Agreements, item (11). The RMR Standard Agreement is included in Section 22, Protocols Agreements.

(6) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability. A combined cycle Facility will 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(s) accepted for RMR Service and a proportionate portion of the steam turbine will 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 Gas Price Index, except when the steam turbine is off-line. ERCOT shall post the criteria upon which it evaluates whether an RMR Unit meets the test of operational necessity to support ERCOT System reliability. A Generation Entity can obtain RMR Agreements only where necessary to ensure ERCOT System reliability according to the Operating Guides.

(7) A Generation Entity cannot be compelled to enter into an RMR Agreement. Owners of Generation Resources that are uneconomic to remain in service can voluntarily petition ERCOT for contracted RMR status by following the process in Subsection 6.5.9.1, Application and Approval of RMR Agreements. ERCOT will be required to determine whether the unit is necessary for system reliability based on the criteria set forth in Subsection 6.5.9(6). If ERCOT determines that the nominated unit is required for system reliability, the Generation Entity may request ERCOT to allow operation as a Synchronous Condenser in place of RMR operation. If Synchronous Condenser

operation is offered by the Generation Entity, ERCOT shall accept Synchronous Condenser operation unless ERCOT reasonably determines that a Synchronous Condenser operation is not adequate to meet system reliability according to the Operating Guides.

(8) ERCOT must contract for the entire capacity of each RMR Unit.

(9) RMR Units may not participate in the bilateral capacity and energy markets, including Self-Arranged Ancillary Services. RMR Units may participate in the Balancing Energy Service market during times when ERCOT has requested the RMR Unit to run at less than full capacity, provided such participation does not limit availability to ERCOT to less than the Operational and Environmental Limitations as described in the RMR Agreement. ERCOT will endeavor to Dispatch an RMR Unit prior to procuring OOMC, OOME, or Zonal OOME Services from other Generation Entities, if economic to do so, based on ERCOT's knowledge at the time, and provided that the RMR Unit supplies equivalent reliability support as would the OOMC, OOME, or Zonal OOME Service, and further provided that the availability constraints of the RMR Unit are maintained. Within two (2) weeks following any month in which an RMR Unit is dispatched, the owner/operator of the RMR Unit will inform ERCOT of the RMR Unit's remaining availability.

(10) RMR Units are dispatched by ERCOT when necessary to provide ERCOT System security, including any emergency situation.

(11) ERCOT will treat the undeployed energy from RMR Units like any other unit for purposes of Balancing Energy Service Up provided the time of use constraints of the RMR Unit are maintained.

(12) ERCOT will administer RMR Agreements in such a way as to minimize the use of RMR Units as much as practicable. ERCOT will provide to all Market Participants all information relative to the use of RMR Units including energy deployed.

(13) The Generation Entity which owns the RMR Unit may not use the RMR Unit for:

(a) Participation in the bilateral energy market;

(b) Self-provision of energy except for plant auxiliary Load obligations under the RMR Agreement;

(c) Provision of Self Arranged Ancillary Services to any Entity; and

(d) Ancillary Services markets, except for incremental bids into the Balancing Energy Services market to the extent allowed in the RMR Agreement.

6.5.9.1 Long-term Outage Notifications and Initiation and Approval of RMR Agreements

(1) Except for the occurrence of a Forced Outage, a Generation Entity must notify ERCOT in writing no less than ninety (90) days prior to the date on which the Generation Entity intends to cease or suspend operation of a Generation Resource in the ERCOT Transmission Grid for a period of greater than one hundred eighty (180) days by submitting a completed Part I of the Notification of Suspension of Operations ("Notification") (Section 22, Attachment I, Notification of Suspension of Operations).

(a) The Generation Entity may also complete Part II of the Notification and submit it along with Part I, or may wait to submit Part II until ERCOT makes an initial determination of the need for the Generation Resource as RMR. The Part I Notification must include a corporate officers' attestation that a Generation Resource will be unavailable for Dispatch by ERCOT for a period specified in the Notification.

(b) Unless ERCOT has notified the Generation Entity that a Generation Resource subject to an existing RMR Agreement will not be required after the expiration or termination of the RMR Agreement, at least sixty (60) days prior to the expiration of the RMR Agreement, the Generation Entity shall submit a new Notification (including both Part I and Part II).

(c) If a Generation Entity submits a Notification for a Generation Resource reporting that the Generation Resource will be mothballed and the Generation Entity later determines that the Generation Resource will remain mothballed for a longer time frame than originally reported, the Generation Entity shall not submit another Notification. Instead, the Generation Entity shall submit updated information to ERCOT pursuant to Section 6.5.9.3, Mothballed Generation Resource Time to Service Updates.

(d) In the instance of a Forced Outage, a Generation Entity shall submit a Part I Notification within fourteen (14) days of the start of the Forced Outage if the Generation Entity does not plan to return the Generation Resource to service within one hundred eighty (180) days.

(2) Upon receipt of the Part I Notification, ERCOT shall post on the MIS all existing relevant studies and data and ERCOT shall provide electronic Notice to all Registered Market Participants of the Notification.

(3) Within fourteen (14) days, following the postings described in Subsection 6.5.9.1(2), 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 meets the test of operational necessity to support ERCOT System reliability as described in Subsection 6.5.9, Reliability Must Run Service, item (4). ERCOT shall consider and post all submitted comments on the MIS.

(4) Within eighteen (18) days of receiving Notification, ERCOT will make an initial determination of whether the Generation Resource is required to support ERCOT System reliability. ERCOT will post this determination on the MIS and notify the Generation Entity of the determination.

(5) Within ten (10) days of an initial determination by ERCOT that the Generation Resource is required to support ERCOT System reliability, the Generation Entity shall complete Part II of the Notification of Suspension of Operations (Section 22, Attachment I, Notification of Suspension of Operations). Upon receipt of Part II, ERCOT and the Generation Entity shall begin good faith negotiations on an RMR Agreement. ERCOT shall post the Part II information on the MIS. The Generation Entity shall also submit a detailed budget for the Resource no later than forty-five (45) days prior to the date on which the RMR Agreement must be executed.

(6) Within sixty (60) days of receiving the Part I Notification, ERCOT will make a final assessment of whether the Generation Resource is required to support ERCOT System reliability. If ERCOT determines that the Generation Resource is required, and the RMR Agreement between ERCOT and the Generation Resource has not yet been finalized, good faith negotiations will continue. 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 Notification.

(7) If, after ninety (90) days following ERCOT's receipt of the Part I Notification, either ERCOT has not informed the Generation Entity that the Generation Resource is not needed for ERCOT System reliability or both parties have not signed a RMR Agreement for the Generation Resource, then the Generation Entity may file a complaint with the PUCT pursuant to subsection (f)(1) of P. U. C. SUBST. R. 25.502, Substantive Rules Applicable To Electric Service Providers.

(8) If, after ninety (90) days following receipt of the Part I Notification, ERCOT and the Generation Entity have not finalized an RMR Agreement for a Generation Resource that ERCOT has determined to be required for ERCOT System reliability, then the Generation Entity shall maintain the Resource so that it is available for OOM Dispatch Instructions until no longer required to do so pursuant to P. U. C. SUBST. R. 25.502(f)(2).

(9) After conducting the analysis required by these Protocols and after the date on which it executes an RMR Agreement, ERCOT shall provide Notice to the Board, at the next Board meeting after ERCOT has signed the RMR Agreement, that the following steps have been completed with respect to any RMR Agreement signed by ERCOT:

(a) The Generation Entity provided a complete and timely Notification including a sworn attestation supporting its claim of pending plant closure.

(b) ERCOT received all the data requested from the applicant necessary to evaluate the need for and provisions of the RMR Agreement. Such information was posted on the MIS by ERCOT, as it became available to ERCOT and no later than prior to execution of the RMR Agreement;

(c) The recommended RMR Agreement is consistent with the ERCOT Protocols; and

(d) ERCOT evaluated:

(i) The reasonable alternatives to a specific RMR Agreement that exist and compared the alternatives against the feasibility, cost and reliability impacts of the proposed RMR Agreement;

(ii) The timeframe in which ERCOT expects each unit to be needed for reliability; and

(iii) The specific type/scope of reliability concerns identified for each potential RMR Unit.

(10) ERCOT shall post on the MIS as they become available, unit-specific studies, reports, and data, by which ERCOT justifies entering into the RMR Agreement.

6.5.9.2 Exit Strategy from an RMR Agreement

(1) No later than ninety (90) days following the execution of an RMR Agreement, ERCOT shall report to the Board and post on the MIS 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 normal 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 shall consider include, but are not limited to, construction of new or expansion of existing Transmission Facilities, installation of voltage control devices, solicitation or auctions for interruptible Load from Retail Electric Providers, or extension of 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.

(2) ERCOT shall provide reasonably available information that would enable potential MRA Resources to assess the feasibility of submitting a proposal to provide a more cost-effective alternative to an RMR Unit through the regional planning process, including any known minimum technical requirements and/or operational characteristics required to eliminate the need for the RMR Unit. TAC shall review the output of the Regional Planning process and provide guidance prior to entering into the MRA.

(3) Subsequent to the process identified in (2) above, ERCOT may negotiate a contract for an MRA Resource that:

(a) technically provides an acceptable solution to the reliability concern that would otherwise be solved by the RMR Unit(s);

(b) will provide a more cost-effective alternative to continued service by the RMR Unit (evaluated over the exit strategy period) provided, however, that no proposed

MRA Resource will be considered if it does not provide at least $1 million in annual savings over the projected net annualized costs for the RMR unit; and

(c) satisfies objective financial criteria to demonstrate that the seller is reasonably able to fulfill its performance obligations as determined by ERCOT.

(4) If the resulting MRA Agreement would result in significantly lower total costs (on a risk adjusted basis) than continued service by the RMR Agreement, and otherwise meets the requirements of this subsection, ERCOT may execute the Agreement. The term of the proposed MRA Agreement shall be limited to the time period until the cost-effective transmission alternative can be implemented.

(5) If the execution of an MRA Agreement would result in the foreclosure of other technically viable solutions (e.g., the RMR Resource that is being replaced by the MRA Agreement retires and is no longer available as an alternative to the MRA Agreement), the MRA Agreement shall include terms and conditions that limit the MRA Resource owner's ability to withdraw or raise the price of the MRA Agreement in future years until a transmission solution can be implemented.

(6) For any MRA Agreement entered into by ERCOT, ERCOT shall annually update the list of feasible alternatives developed in Section 6.5.9.2(1) and provide an update of that information to the TAC and the ERCOT Board.

6.5.9.3 Generation Resource Return to Service Updates

(1) By April 1st and October 1st of each year and when material changes occur, every Generation Entity that owns or controls a Mothballed Generation Resource or an RMR Unit with an approved exit strategy 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 Generation Entity expects to return to service in each Season of each of the next five (5) years.

(2) A Generation Entity with a Mothballed Generation Resource that has been in mothballed status for ninety (90) days or more shall notify ERCOT in writing no less than thirty (30) days prior to the date on which the Generation Entity intends to return a Mothballed Generation Resource to service by completing a Notification of Change of Generation Resource Designation (Section 22, Attachment M: Notification of Change of Generation Resource Designation). A Generation Entity with a Mothballed Generation Resource that has been in mothballed status for less than ninety (90) days shall notify ERCOT in writing no less than ninety (90) days prior to the date on which the Generation Entity intends to return a Mothballed Generation Resource to service by completing a Notification of Change of Generation Resource Designation (Section 22, Attachment M: Notification of Change of Generation Resource Designation). ERCOT shall post the Notification of Change of Generation Resource Designation on the MIS within five (5) days of receipt. If a Generation Entity wishes to change the operational designation of a Generation Resource upon conclusion of an RMR Agreement, it must submit a

Notification of Change of Generation Resource Designation no later than sixty (60) days prior to the conclusion of the RMR Agreement.

(3) For modeling purposes, ERCOT and TSPs shall rely on the most recently submitted of the following two forms with respect to RMR, Mothballed or decommissioned Generation Resources: Section 22, Attachment I or Section 22, Attachment M. If a Generation Resource is designated as decommissioned and retired under either notification, ERCOT will permanently remove the Generation Resource from the ERCOT registration system. If a Generation Entity decides to bring a decommissioned Generation Resource back to service at a later date, it must follow the procedures for interconnecting new generation. If the Generation Resource is designated as mothballed, ERCOT and TSPs will consider the Generation Resource mothballed until the Generation Entity indicates a definitive return to service date pursuant to this section.

6.5.9.4 Transmission System Upgrades Associated with an RMR and/or MRA Exit Strategy

This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(1) ERCOT and the TDSP(s) responsible for constructing 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.

(2) The TDSP(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 8.8, Coordination for System Topology Modifications. For purposes of this section, a Transmission Facility upgrade will be considered initiated upon the TDSP authorizing any expenditures on the upgrade including, but not limited to, material procurement, right-of-way acquisition, and regulatory approvals.

(3) Upon initiation of the project, the TDSP(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 12.4.4.2.2, TDSP Responsibility. Within sixty (60) days of the completion date shown in the Notice provided per Section 8.8, Coordination for System Topology Modifications, for the Transmission Facilities upgrades, the TDSP will coordinate more timely updates if the timeline changes significantly.

(4) Within ten (10) 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.

6.5.9.5 RMR or MRA Contract Termination

This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(1) Once a suitable RMR or MRA exit strategy has been developed as defined in Section 6.5.9.2, Exit Strategy from an RMR Agreement, and the strategy has been approved by the ERCOT Board and the affected TDSP(s), the TDSP(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 CCN application timeline for projects requiring such PUCT certification. Once a CCN has been granted by the PUCT, the TDSP(s) shall be required to meet the requirements in item (a) above.

(2) ERCOT will review and approve or reject each construction outage schedule as provided in accordance with procedures developed by ERCOT in compliance with Protocols Section 8, Planned Outages and Maintenance Outages of Transmission and Resource Facilities.

(3) The TDSP(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 (5) Business Days of ERCOT's request.

(4) If ERCOT determines that a mutually agreeable preliminary construction outage schedule can be accommodated during the fall, winter, or spring, ERCOT and the TDSP shall collaborate to determine if the ninety (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 TDSP may give consideration to the risk of the decision to terminate the RMR and/or MRA Agreement and any options, such as Remedial Action Plans and/or Mitigation Plans that could be used to mitigate transmission construction delays.

6.5.9.6 RMR and/or MRA Contract Extension

This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(1) Forty-five (45) days prior to the termination date of an existing RMR or MRA Agreement, pursuant to the 90-day termination notice as described in Section 22F3A2, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) necessary to allow termination of an existing RMR or MRA Agreement based

on the updates of project status provided by the TDSP(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 the RMR Unit or MRA Resource of its intent to execute an extension to the existing RMR or MRA Agreement no later than thirty (30) days prior to the planned termination date.

(2) Forty-five (45) days prior to the expiration date of an existing RMR or MRA Agreement for which the Generation Entity 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 TDSP(s). If ERCOT determines that an extension of the existing RMR or MRA Agreement of no more than ninety (90) days would allow completion of the Transmission Facilities upgrade(s), it shall provide written notice to the Resource Entity that owns the RMR Unit or MRA Resource of its intent to execute an extension to the existing RMR or MRA Agreement no later than thirty (30) days prior to the planned expiration date.

(3) 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 ninety (90) days from the termination or expiration date of the existing RMR or MRA Agreement.

(4) Forty-five (45) 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 the RMR or MRA Resource to negotiate a new RMR or MRA Agreement to allow completion of the planned transmission upgrades.

6.5.10 Out of Merit Capacity and Out of Merit Energy Services

(1) ERCOT will use OOMC and OOME Services to procure additional capacity and energy required to provide reliable ERCOT System operation, or to effectively manage Local Congestion as determined by ERCOT.

(2) ERCOT may call on any Generation Resource to provide OOMC or OOME Service, in any time frame that the Resource is listed as available in its Resource Plan. ERCOT may interrupt Loads Acting as Resources to provide OOME Service when the Load Resource is listed as available in its Resource Plan.

(3) For combined cycle plants, or other plants that involve tandem operation of Resources, a Generation Entity may request ERCOT approval to treat the plant at which these Resources are located as an Aggregated Unit.

(4) ERCOT may use OOMC when necessary to provide ERCOT System security and capacity adequacy. ERCOT will Dispatch Resources for OOMC and OOME Service in such a way as to minimize the use of these services as much as practicable.

(5) ERCOT may, at its discretion, use OOMC Service as necessary to effectively manage Local Congestion if either of the following conditions apply:

(a) The Resource-specific deployments necessary to manage a specific Local Congestion problem are expected to use Resources that have Generation Shift Factors of less than or equal to five percent (5%) impact on the congested element; or

(b) The total amount of Resource-specific deployments to manage a single Local Congestion situation exceeds one thousand (1,000) MW.

(6) Consistent with Section 2.2.2 of the ERCOT Operating Guides, ERCOT will evaluate the need for Resource-specific deployments during Real Time operations for management of Local Congestion by excluding the Forced Outage of any double circuit transmission line as a credible single contingency, unless the transmission line meets the criteria of High Outage Probability or High Outage Consequence as those terms are defined in Section 4.3 of the ERCOT Operating Guides.

(7) ERCOT will settle OOME Service in accordance with the Balancing Energy settlement provisions in Section 6.8.2.3, Energy Payments.

(8) ERCOT may also use bids from Loads acting as Resources under the OOME Dispatch Instructions and pricing structure.

(9) The QSE associated with Generation Resources receiving a Dispatch Instruction to provide OOMC and/or OOME Service(s) and/or LaaRs providing OOME Service(s) only must use all commercially reasonable efforts to provide the requested service(s). If the QSE declines the Dispatch Instruction to provide OOMC and/or OOME Service(s) pursuant to the provisions of Section 5.4.4, Compliance with Dispatch Instructions, ERCOT will post such declines on the MIS.

(10) If ERCOT Dispatches a Resource for OOMC Service to sustain reliable ERCOT System operation or effectively manage Local Congestion, the QSE receiving the Dispatch Instruction must bid into the Balancing Energy Up and Down market quantities which sum greater or equal to the High Sustainable Limit (if unavailable, the High Operating Limit) minus the Low Sustainable Limit (if unavailable, the Low Operating Limit) of the Resource receiving the OOMC Dispatch Instruction, in the Congestion Zone of the Resource that receives the OOMC Dispatch Instruction.

On or before the second (2nd) Business Day after each Operating Day, ERCOT will post on the MIS, for such Operating Day:

(a) Each Resource receiving an OOMC Dispatch Instruction;

(b) Intervals for which a Resource received an OOMC Dispatch Instruction;

(c) The Low Sustainable Limit for each Resource receiving an OOMC Dispatch Instruction; and

(d) In the case of Congestion, the binding transmission constraint (contingency and/or overloaded element(s)) causing the OOMC deployments.

(11) For OOME Dispatch Instructions, ERCOT will post the following information on the MIS, for each Operating Day:

(a) On or before the second (2nd) Business Day following the Operating Day on which ERCOT issued the Dispatch Instruction, each Resource receiving an OOME Up Dispatch Instruction for each interval;

(b) On or before the second (2nd) Business Day following the Operating Day on which ERCOT issued the Dispatch Instruction, each Resource receiving an OOME Down Dispatch Instruction for each interval ;

(c) On or before the Business Day following the day of issuance of the Initial Statement for the Operating Day on which ERCOT issued the Dispatch Instruction, as described in Section 9.2.3, Initial Statements, the amount of OOME Up provided by each Resource for each interval;

(d) On or before the Business Day following the day of issuance of the Initial Statement for the Operating Day on which ERCOT issued the Dispatch Instruction, as described in Section 9.2.3, Initial Statements, the amount of OOME Down provided by each Resource for each interval; and

(e) The binding transmission constraint (contingency and/or overloaded element(s)) causing OOME deployments shall be posted on or before the second (2nd) Business Day.

(12) Should the removal of an OOME Instruction require a QSE to exceed its ramp rate in order to resume its schedule, the QSE may dispute the settlement with a showing of unit's actual ramp. Such disputes should base settlement on appropriate OOME payments being provided the QSE at the unit's maximum ramp rate until that rate allows the QSE to resume its schedule. Upon verification of the data provided, ERCOT shall grant such disputes.

6.5.11 Zonal Out-of-Merit Energy Service

(1) ERCOT will use Zonal OOME Deployments to procure additional energy required to provide reliable ERCOT System operation, as determined by ERCOT. Zonal OOME Deployments shall not be used to bring on additional capacity.

(2) Any QSE with Generation Resources may be called upon by ERCOT to provide Zonal OOME Service in any time frame that the Resources are listed as on line in the Resource Plan.

(3) Zonal OOME is used by ERCOT only when necessary to provide ERCOT System security and only after other Congestion management techniques have failed to clear a Congestion problem. ERCOT will call on Zonal OOME Service in such a way as to minimize the use of this service as much as practicable.

(4) Zonal OOME will be settled in accordance with Section 6.8.2.5, Settlement of Zonal OOME Deployments.

(5) The QSE associated with the Generation Resources that receives a Zonal OOME Dispatch Instruction must use all commercially reasonable efforts to provide the requested service. If the QSE declines the Dispatch Instruction according to the provisions of Section 5.4.4, Compliance with Dispatch Instructions, of these Protocols to provide Zonal OOME Service(s), ERCOT will post such declines on the MIS.

(6) Upon a SPS actuation the TSP shall inform ERCOT of the time of actuation. The affected QSE(s) will receive a verbal Dispatch Instruction OOME instruction corresponding with the actuation that will last no longer than four (4) hours after the time of actuation. If the actuation results in a unit being taken Off-line then ERCOT will proceed in accordance with the OOME Off-line Dispatch in Section 6.5.10 (12), Out of Merit Capacity and Out of Merit Energy Services.

(7) In the event a SPS triggers a trip of a DC Tie, the QSE(s) scheduling the DC Tie shall be entitled to OOME payment based on the quantity of power being imported as defined by the amount shown in the NERC tag effective at the time of the SPS actuation. ERCOT will proceed in accordance with OOME down Dispatch provisions in Section 6.8.2.3 (4), Energy Payments, utilizing the RCGFC category (Combined Cycle greater than 90 MW** = FIP * 5 MMBtu/MWh). The QSE(s) scheduling the DC Tie will be entitled to OOME payments for the duration the DC Tie is Off-line up to a maximum of four (4) hours.

** Determined by capacity of largest simple cycle combustion turbine in the train.

6.5.12 Emergency Interruptible Load Service (EILS)

(1) ERCOT shall procure Emergency Interruptible Load Service (EILS) for EILS Contract Periods. The standing EILS Contract Periods are as follows:

(a) June through September;

(b) October through January; and

(c) February through May.

ERCOT may restructure EILS Contract Periods in order to facilitate additional Load participation in EILS. ERCOT shall provide Notice of any changes to the standing EILS Contract Periods no less than ninety (90) days prior to the start date of that EILS Contract Period.

(2) ERCOT will request EILS bids prior to each EILS Contract Period. ERCOT may procure additional EILS at any time.

(3) The steps for procuring EILS in an EILS Contract Period are as follows:

(a) A QSE electing to self-provide part or all of its EILS obligation shall provide ERCOT with the following:

(i) The maximum MW of Capacity it is willing to offer through EILS Self-Provision, per Time Period;

(ii) A Proxy Load Ratio Share specific to the Time Period and Contract Period. "Proxy Load Ratio Share" shall be a number between zero (0) and one (1) and determined by the self-providing QSE to represent its estimate of its final Load Ratio Share to be used in EILS settlement.

(b) After receiving EILS Self-Provision information, ERCOT will enter contracts for additional MWs of EILS capacity such that EILS capacity procured through EILS bids and the combined maximum MW capacity for EILS Self-Provision do not exceed one thousand (1,000) MW.

(c) If the total amount of EILS capacity procured through bids and EILS Self-Provision equals one thousand (1,000) MW, a QSE shall not change its EILS Self-Provision capacity obligation.

(d) If the total amount of EILS capacity procured through bids and offered through EILS Self-Provision is less than one thousand (1,000) MW, ERCOT shall provide QSEs offering EILS Self-Provision their adjusted estimated obligation based on their Proxy Load Ratio Shares. A QSE may then reduce its EILS Self-Provision capacity to a number no lower than the lowest number represented in the following three (3) options:

OPTION 1

The capacity of MW procured by ERCOT through bids divided by one (1) minus the sum of EILS Self-Provision Proxy Load Ratio Shares multiplied by the QSE's Proxy Load Ratio Share, as expressed in the following formula:

$$\mathbf{(Total\_BIDProc_{qc(tp)} / (1-\sum ProxSPLRS_{qc(tp)}))*ProxSPLRS_{qc(tp)}}$$

Where:

q QSE

c	EILS Contract Period
tp	Hours in an EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$Total\_BIDProc_{qc(tp)}$	Total capacity (MW) procured by ERCOT from competitive EILS bids for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$ProxSPLRS_{qc(tp)}$	The value (in percent) reported by each QSE of its estimated Load Ratio Share for EILS for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

OPTION 2

The sum of the capacity procured by ERCOT and the capacity self-provided multiplied by the QSE's Proxy Load Ratio Share, as expressed in the following formula:

$$\mathbf{(Total\_BIDProc_{qc(tp)} + \sum OfferedSP_{qc(tp)})*ProxSPLRS_{qc(tp)}}$$

Where:

q	QSE
c	EILS Contract Period
tp	Hours in a EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$OfferedSP_{qc(tp)}$	The capacity in MW offered by a QSE for Self-Provision for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period, as communicated to ERCOT prior to ERCOT procuring competitive EILS bids.
$Total\_BIDProc_{qc(tp)}$	Total Capacity (MW) procured by ERCOT from competitive EILS bids for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$ProxSPLRS_{qc(tp)}$	The value (in percent) reported by each QSE of its estimated Load Ratio Share for EILS for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

OPTION 3

The QSE's declared maximum MW offer self-provided capacity.

(e) A QSE with reduced EILS Self-Provision capacity may reduce the commitment(s) of specific EILS Resources by providing notification to ERCOT. Such notification must be received by ERCOT within two (2) Business Days following ERCOT's notification to the QSE of its reduced obligation.

(f) If a QSE reduces its EILS commitment according to these procedures, it will not be obligated to pay EILS charges so long as the amount of its Self-Provision capacity remains equal to or greater than its final Load Ratio Share of the total EILS capacity procured through bids and EILS Self-Provision, as described in Section 6.9.4.4, Settlement Obligation for Emergency Interruptible Load Service, item (1), and so long as all self-provided EILS Resources meet their availability and performance obligations as described in Section 6.10.13.3, Performance Criteria for EILS Resources.

(4) EILS bids may be submitted to ERCOT by a QSE capable of receiving verbal Dispatch Instructions on behalf of a represented EILS Resource. A QSE on behalf of an EILS Resource may submit multiple EILS bids for any EILS Contract Period.

(5) ERCOT shall solicit EILS bids. QSEs, on behalf of EILS Resources, may submit bids for one (1) or more EILS Time Periods as defined by ERCOT in the Request for Proposal specific to the Contract Period.

(6) The minimum amount of EILS that may be offered in a bid to ERCOT is one (1) megawatt (MW). EILS Resources may be aggregated to reach the one (1) MW bid requirement.

(7) A bid to provide EILS shall include:

(a) The name of the QSE representing the EILS Resource;

(b) The name of the Entity supplying the EILS Resources;

(c) A description of the Resource(s) which will provide EILS if selected, including name(s) and Electric Service Identifier(s) (ESI ID(s));

(d) The EILS Time Period for which the bid is submitted, as defined in the Request for Proposal specific to the Contract Period;

(e) A dollars per MW price for the capacity bid unless the bid is for EILS Self-Provision;

(f) The quantity of capacity for which the bid price is effective and whether the capacity is available in blocks or individual MWs;

(g) The minimum base Load, in MW, for each ESI ID in the EILS Resource, defined as that level of Load below which the EILS Resource is unwilling to operate;

(h) For Non Opt-In Entity (NOIE) EILS Resources, the most recently available twelve (12) months of Interval Data Recorder (IDR) data in a format specified by ERCOT;

(i) QSEs opting for EILS Self-Provision must provide ERCOT with the maximum amount of capacity they plan to provide through this option before ERCOT begins to accept EILS bids;

(j) A QSE opting for EILS Self-Provision may offer capacity into EILS in the form of a priced bid in the same manner as any other QSE; and

(k) Affirmation that the capacity being offered into EILS is not capacity that is separately obligated to respond during an EEA event, and receiving a separate reservation payment for such obligation, occurring in the contracted EILS Time Period and EILS Contract Period.

(8) ERCOT shall not procure more than $50 million of EILS in any twelve (12) month period beginning on February 1st and ending on January 31st (“EILS Cap”). ERCOT may determine cost limits for each EILS Contract Period in order to ensure that the EILS Cap is not exceeded. In order to minimize the cost of EILS, ERCOT may reject any bid it determines to be unreasonable or outside the parameters of an acceptable bid. ERCOT shall establish a written process for determining the cost limits for each EILS Contract Period and for the reasonableness of bids.

(9) ERCOT shall reduce the EILS Cap by the value of the amount of EILS Self-Provision. ERCOT shall value EILS Self-Provision at the weighted average cost per MW of the EILS procured multiplied by the total MW of EILS Self-Provision during each relevant EILS Time Period and EILS Contract Period.

(10) The maximum amount of EILS for which ERCOT may contract in an EILS Contract Period is one thousand (1,000) MW for each EILS Time Period.

(11) ERCOT may evaluate each bid to determine the actual capacity an EILS Resource is capable of providing and may limit any award based upon that EILS Resource accordingly.

(12) ERCOT shall select EILS Resources for each EILS Time Period to serve during an EILS Contract Period based upon least cost bid per MW of capacity bid based upon the payment as bid for selected EILS Resources; provided that ERCOT may consider geographic location and its affect on Zonal or Local Congestion in selecting EILS Resources. ERCOT may prorate awards when there are more MWs available at a given price than ERCOT can procure, if acceptable to the bidding QSE. An EILS bid may declare a minimum amount of MW that the EILS Resource is willing to provide and, if pro-ration would result in an award below that amount, the bid will be excluded from the EILS procured.

(13) QSEs representing selected EILS Resources, except for Load designated for EILS Self-Provision, will be entitled to payment as bid, subject to adjustment, pursuant to the Protocols. Deployment of EILS Resources will not result in additional payments other than any Load Imbalance payments received.

(14) QSEs representing EILS Resources selected to provide EILS shall execute a Standard Form EILS Agreement, as provided in Section 22, Attachment K, Standard Form Emergency Interruptible Load Service (EILS) Agreement, for each EILS Time Period and EILS Contract Period ERCOT selects the EILS Resource(s).

(15) An EILS Resource shall be subject to a maximum of two (2) Dispatch Instructions per EILS Contract Period. Additionally, an EILS Resource shall be subject to a maximum of eight (8) hours of Dispatch Instructions per EILS Contract Period, unless an EILS deployment is still in effect when the eighth hour lapses (in which case the EILS Resource must follow the Dispatch Instruction until ERCOT releases the EILS Resource).

(16) Unless ERCOT has received a Notice of unavailability in a format prescribed by ERCOT, ERCOT shall assume that such a contracted EILS Resource is fully available for receiving Dispatch Instructions.

(17) EILS Resources shall meet the following technical requirements:

(a) Each EILS Resource must have an ESI ID or other unique service identifier, as defined by ERCOT. Each EILS Resource must have an installed IDR meter or equivalent, subject to ERCOT approval, dedicated to the Load providing EILS. ERCOT shall analyze fifteen (15) minute interval meter data for each EILS Resource for purposes of bid analysis, availability and performance measurement. EILS Resources behind an NOIE meter point shall arrange, preferably with the NOIE TDSP, to provide ERCOT with fifteen (15) minute interval meter data subject to ERCOT's specifications and approval. EILS Resources behind a Private Use Network's Settlement Meter point shall provide ERCOT fifteen (15) minute interval meter data subject to ERCOT's specifications and approval.

(b) An EILS Resource must be capable of reducing its Load by its contracted capacity compared to its baseline capacity within ten (10) minutes of an ERCOT Dispatch Instruction to its QSE and must be able to maintain such reduced capacity level for the entire period of the Dispatch Instruction and shall not return to normal operations until released to do so by ERCOT. The ERCOT EILS Dispatch Instruction to a NOIE opting for EILS Self-Provision which is also dynamically scheduling shall be considered an instructed deviation so the NOIE is not penalized for keeping Generation Resources On-line.

(c) Any QSE representing an EILS Resource must be capable of communicating with its EILS Resources within the prescribed time constraints for deployment of EILS.

(d) Committed EILS Resources are responsible for communicating any material changes in availability status to the QSE representing the EILS Resource and to ERCOT, irrespective of whether the change in availability is scheduled with ERCOT as described in paragraph (b)(i) of Section 6.10.13.3.

(e) EILS Resources deployed for EILS must be able to return to their contracted operating level for providing EILS within ten (10) hours following a release Dispatch Instruction.

(f) EILS Resources and their QSEs are subject to qualification, testing and performance requirements as described in Section 6.10.13, Emergency Interruptible Load Service Qualification, Testing and Performance Standards.

(g) EILS Resources shall not be subject to the modeling, telemetry and Resource Plan requirements of other Resources.

(18) The contracted capacity of EILS Resources may not be used to provide Ancillary Services or Balancing Energy Services during the contracted EILS Time Period of the contracted EILS Contract Period. Nothing herein shall be construed to limit passive (voluntary) Load response provided the EILS performance requirements of this Section 6.5.12, Emergency Interruptible Load Service (EILS) are met.

(19) ERCOT will review the effectiveness and benefits of the EILS every twelve (12) months from the start of the program and report its findings to TAC.

(20) Within ten (10) days of the receipt of all executed agreements for EILS from the QSEs whose bids were chosen to provide EILS in an upcoming Contract Period, ERCOT shall post to a publicly accessible page on its website the number of MW procured per EILS Time Period, the number of EILS Resources selected and the projected total cost of EILS for that Contract Period.

6.5.13 WGR Ramp Rate Limitations

(1) Each Wind-powered Generating Resource (WGR) that is part of an Interconnection Agreement signed on or after January 1, 2009 shall limit its ramp rate to ten-percent (10%) per minute of its nameplate rating (MWs) as registered with ERCOT when responding to or released from an ERCOT deployment.

(2) The requirement of pargraph (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 wind resource.

(3) Each WGR that is part of an Interconnection Agreement signed on or before December 31, 2008 and that controls power output by means other than turbine stoppage shall limit its ramp rate to ten percent (10%) 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 wind resource, or during unit start up and shut down mode.

(5) WGRs that meet the technical specifications of paragraph (3) above and which do not comply with its ramp rate requirement shall submit a compliance plan to ERCOT on or before June 1, 2009 which 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 WGR's best efforts to adhere to the WGR ramp rate limitation during the applicable compliance transition period.

(6) WGRs that do not meet the technical specifications of paragraph (3) above must submit an operations plan to ERCOT on or before June 1, 2009 describing the WGR's best efforts to adhere to the WGR ramp rate limitation.

(7) WGRs subject to the ramp rate limitations of paragraphs (1) and (3) above are exempt from the requirements of the applicable section upon receipt of a valid Dispatch Instruction from ERCOT to exceed the applicable ramp rate limitation when necessary to protect system reliability.

(8) WGRs that operate under a Special Protection Scheme (SPS) are exempt from the ramp rate limitations of paragraphs (1) and (3) above when decreasing unit output to avoid SPS activation.

(9) WGRs that meet the requirements of paragraphs (1) and (3) above are compliant with ramp rate limitation requirements when the number of 10-minute averages of eligible intervals meeting ten percent (10%) of nameplate capacity per minute ramp rate limit is equal to or greater than ninety percent (90%) of eligible intervals per month. 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 WGR where the WGR's score is less than ninety percent (90%). Scores that remain below ninety percent (90%) for three consecutive months shall be considered to have failed the ramp rate limitation performance measure.

6.6 Selection Methodology

6.6.1 Qualified Scheduling Entity Rights and Obligations to Self-Arrange Ancillary Service Resources

(1) QSEs may self-arrange only Regulation Up, Regulation Down, Responsive Reserve Services, and Non-Spinning Reserve Services.

(2) A QSE may self-arrange Resources by indicating the amount of each Ancillary Services that will be self-arranged in each hour of the Operating Day.

(3) The quantity self-arranged specified by a QSE at 1100 in the Day Ahead shall not be changed for the Day Ahead Obligation, unless ERCOT allows schedules to be updated at 1300 in accordance with Section 4.4.10, QSE Submittal of Updated Balancing Energy Schedules.

(4) The quantity of Self-Arranged AS specified by a QSE in response to a Notice by ERCOT to obtain additional AS in the Adjustment Period cannot be greater than the allocated additional AS amount and cannot be changed once committed to ERCOT.

(5) QSEs may schedule with ERCOT to provide Ancillary Services on another QSE's behalf by notifying ERCOT consistent with the requirements of Section 4, Scheduling.

6.6.2 Competitive Procurement of Ancillary Service Resources by ERCOT

(1) Except where stated to the contrary in these Protocols, ERCOT shall, to the extent the Ancillary Service Resource bids are available, use competitive procurement processes to procure sufficient Ancillary Service Resources to meet the requirements specified in these Protocols.

(2) QSEs may submit bids to provide Regulation Down, Regulation Up, Responsive Reserves, and Non-Spinning Reserves, as part of the Scheduling Process in accordance with Section 4, Scheduling.

(3) QSEs offering Balancing Energy Up, Balancing Energy Down, and Replacement Reserves can offer bids through the Adjustment Period, in accordance with Section 4.5, Adjustment Period Scheduling Process.

(4) QSE's bids to provide Ancillary Services will continue to be valid until withdrawn by the QSE prior to the market clearing or the market is cleared. Bids may not be withdrawn during bid evaluation by ERCOT as described in Scheduling Sections 4.4 Day Ahead Scheduling Process and Section 4.5 Adjustment Period Scheduling Process or after the bid is selected.

(5) QSEs may only submit bids from that portion of any Resource not used to provide capacity and energy to Supply the Resources in the QSE's Balanced Schedule.

(6) ERCOT will determine the MCPC of each interval for Regulation Up, Responsive Reserve and Non-Spinning Reserve using an optimized simultaneous selection process in order to minimize the overall cost of these Ancillary Services.

(7) Other than as specified for Congestion Management, ERCOT shall select Replacement Reserve and Regulation Down bids based on the lowest bid for each service.

(8) Other than as specified for Congestion Management, ERCOT shall Dispatch energy from the Balancing Energy Service bids based on price Merit Order and the requirements specified in Section 5, Dispatch Instructions.

(9) For Congestion Management, ERCOT shall, if possible, resolve all Congestion using the Balancing Energy Service by Congestion Zone.

(10) ERCOT shall establish, through an annual competitive procurement process, annual agreements with Resources needed to provide Black Start capability.

6.6.3 ERCOT Day-Ahead Ancillary Service Procurement Process

6.6.3.1 General Procurement Requirements

(1) ERCOT shall conduct daily the Day Ahead bidding process for the purpose of procuring the quantities of Resources as specified in the Ancillary Services Plan for all Operating Hours of the next Operating Day to provide Regulation Up, Regulation Down, Responsive Reserves, and Non-Spinning Reserves.

(2) ERCOT shall procure Regulation Up, Responsive Reserve and Non-Spinning Resources in the Day-Ahead market simultaneously for each hour of the next Operating Day such that the overall cost of these Ancillary Services are minimized. ERCOT will also procure Regulation Down and Replacement Reserves, if needed, prior to the end of the Day Ahead market.

(3) ERCOT will procure the amount of each service specified in the Ancillary Service Plan, less the amount self-arranged, without substituting one service for a different service.

(4) A QSE may offer the same Resource capacity into any or all of the Ancillary Services markets simultaneously. A QSE may specify different capacity bids from a single Resource for each of the Ancillary Service markets into which the Resource is bid in compliance with Section 4, Scheduling.

(5) When the same Resource capacity is simultaneously offered for more than one of RGS Up, RRS, and NSRS, ERCOT will select the service for which the capacity will be awarded such that the overall cost of these Ancillary Services is minimized.

(6) For each Ancillary Service procurement process, ERCOT shall select capacity bids submitted by QSEs, such that:

(a) After adjusting for self-arranged Resources, the total amount of capacity procured by ERCOT meets the Ancillary Services Plan requirements; and

(b) For each of RGS Up bid as well as RRS and NSRS bids will be arranged in the Bid Stack such that the overall cost of these Ancillary Services is minimized. For each of these Ancillary Services, if selection of the marginal capacity block will exceed ERCOT's required Ancillary Service quantity, ERCOT will select a portion of this capacity block as the actual marginal AS quantity accepted.

(c) For RGS Down, ERCOT will procure required quantities by selecting capacity in ascending order starting from the lowest priced bid. ERCOT will continue this selection process until the required quantity of RGS Down is obtained.

[PRR496: Revise (b) upon system implementation]

(b) For each of RGS Up bid as well as RRS and NSRS bids that are not designated as block bids will be arranged in the Bid Stack such that the overall cost of these

Ancillary Services is minimized. For each of these Ancillary Services, if selection of the marginal capacity block will exceed ERCOT's required Ancillary Service quantity, ERCOT will select a portion of this capacity block as the actual marginal AS quantity accepted.

(d) In the case where multiple bids have the same price for the selection of RGS Up, RGS Down, RRS and NSRS Ancillary Services, selection shall be awarded proportionately.

PRR496: Add (e) under Section 6.6.3.1(6) upon system implementation and Notice to the Market.

(e) For RRS and NSRS bids that are designated as block bids, if the selection of the Block Bid will exceed ERCOT's required Ancillary Service quantity the bid will be skipped and ERCOT will select the next available bid(s) as the actual marginal AS quantity accepted.

(7) ERCOT shall deduct any Resource capacity accepted in one of the Ancillary Service procurement auctions from the capacity that is available for procurement in any subsequent Ancillary Service procurement auction if the QSE has indicated that the Resource capacity bids are linked.

(8) ERCOT shall determine an hourly MCPC for each of the following Day-Ahead Ancillary Service markets: Regulation Up, Regulation Down, Responsive Reserves and Non-Spinning Reserves. The hourly MCPC shall equal the highest-priced capacity reservation bid accepted in the Day Ahead market by ERCOT for that Ancillary Service for the hour.

(9) If the MCPC cannot be calculated by ERCOT, the MCPC for the particular Ancillary Service shall be deemed to be equal to the MCPC for that Ancillary Service in the same Settlement Period of the preceding Operating Day.

(10) For each of RGS Up, RGS Down, RRS and NSRS, for each hour of the next Operating Day, ERCOT will post the quantity of capacity procured and the MCPC for the Day Ahead market.

[PRR558: Replace (10) above with the following upon system implementation.]

(10) For each of RGS Up, RGS Down, RRS and NSRS, for each hour of the next Operating Day, ERCOT will post the quantity of capacity procured and the MCPC for the Day Ahead market. ERCOT will post a notice if the RRS awarded to LaaR was prorated for any hour.

(11) ERCOT will be capable of using the MCPC for Non-Spinning Reserve as the MCPC for Regulation Up and/or the MCPC for Responsive Reserve. Similarly, the MCPC for Responsive Reserve could be used for Regulation Up. ERCOT shall not substitute prices until a determination of the conditions to allow substitution of prices from one service to another is approved by the ERCOT Board.

6.6.3.2 ERCOT Ancillary Services Procurement during Adjustment Period (AP)

During the Adjustment Period, ERCOT may procure Replacement Reserves; or as a result of changing conditions, may procure additional Regulation Up, Regulation Down, Responsive and Non-Spinning Services, as appropriate for the conditions, in order to maintain ERCOT System reliability.

ERCOT may procure Ancillary Services to replace those previously awarded to a provider who has subsequently defaulted on his Obligation. The defaulting Entity will be financially responsible for the total cost of the Ancillary Services procured in the markets opened due to the default.

If ERCOT requires any Replacement Reserves; or additional Regulation, Responsive Reserve or Non-Spinning Reserve Services during the Adjustment Period, then ERCOT will implement the Notification process for these services in accordance with Section 4, Scheduling.

If ERCOT forecasts that there is insufficient capacity available to reliably serve system Load in any settlement period, ERCOT will implement the Notification process for Replacement Reserve Services in accordance with Section 4, Scheduling.

Additional Ancillary Services will be allocated to QSEs using the same percentages as the Day Ahead allocation except when the purchase is in the case of a default. In this case the Ancillary Service costs shall be allocated to the defaulting Entity as provided in above.

6.6.3.2.1 Specific Procurement Process Requirements for Replacement Reserve Service in the Adjustment Period

ERCOT shall procure Replacement Reserve Service (RPRS) in the AP as follows:

(1) ERCOT will evaluate Zonal Congestion, Local Congestion, and capacity insufficiency using ERCOT's Operational Model, balanced QSE schedules, Resource Plans, and ERCOT forecast of next day Load.

(2) ERCOT will define the level of Resources available to meet next-day reliability needs of the ERCOT System based on QSE schedule submissions, Resource Plans and ERCOT Load forecast. ERCOT will determine incremental Resource capacity available from Generation Resources that are Off-line, or Generation Resources that are expected to be Off-line in the requested hours or Loads acting as a Resource shown as available in the Resource Plans.

(3) RPRS procurement produces an optimum solution for the whole Operating Day. The RPRS procurement resolves Local Congestion problems first and then resolves capacity inadequacy and Zonal Congestion problems simultaneously. The solution of the RPRS is a result of ERCOT performing analysis of the current physical system operations for each hour to recognize potential transmission constraints that would require Resources not currently planned to be available. The purpose and use of the RPRS procurement is to provide capacity from which energy would be available to solve the following system security violations:

(a) ERCOT System capacity insufficiency using any RPRS bid;

(b) Zonal Congestion using the RPRS bids by Congestion Zone in bid price Merit Order and the current physical system operations in the ERCOT System; and

(c) Local Congestion using Resource Category Generic Cost and the current physical system operations in the ERCOT System.

(4) ERCOT will solve security violations using a transmission security-constrained mathematical optimization application. The application will solve as if each bid can be proportioned into individual MW bids. The objective of the optimization is to minimize the total cost, based on Resource Category Generic Cost, capacity price, operation price, and Resource Shift Factors, as described in Section 4.4.16, ERCOT Receipt of Replacement Reserve Service Bids, as well as lead time, minimum up time, and minimum down time captured through the registration process, for the whole Operating Day while satisfying all the security constraints for each hour.

(5) The costs associated with resolving system security violations will be identified separately into the following categories: capacity inadequacy, Zonal Congestion, and Local Congestion.

[PRR676: Delete Section 6.6.3.2.1(5) above, upon system implementation.]

(6) The Market Clearing Prices on the capacity insufficiency, CSC constraint, and Operational Constraint will represent the marginal cost for the solution of each constraint and will be produced as an output of the mathematical optimization application. The output of the application will be as follows:

(a) The marginal cost (Shadow Price of the power balance constraint) to solve system insufficiency defines MCPC for insufficiency.

(b) The marginal cost (Shadow Price of the CSC constraint) to solve a CSC constraint defines the Congestion price of the CSC constraint.

(c) The bidder of RPRS shall be paid the higher of RPRS bid price (as defined in Section 6.8.1.10, Zonal or System Wide Replacement Reserve Service Capacity Payment to QSE) and MCPC of the Congestion Zone unless the bid has been selected to solve Local Congestion. Resources taken to solve Local Congestion shall be paid in accordance with the Local Congestion Replacement Reserve formula in Section 6.8.1.11, Local Congestion Replacement Reserve Payment to QSE.

(7) QSEs whose schedules have impacts on CSCs according to the Commercial Model (using zonal Shift Factors at the time of RPRS procurement for each Zone) shall be charged Congestion costs associated with the impact.

(8) The costs of resolving Local Congestion are based on the amount of capacity required to solve Local Congestion. This cost will be tracked by specific constraint to aid the determination of the potential addition to the constraint as a CSC.

(9) If all of the cost of RPRS is not allocated by one of the above methods, then the allocation will be uplifted to all QSEs based on the Load Ratio Share for the relevant period. If ERCOT collects more RPRS costs in this manner than are necessary, the excess funds collected by ERCOT will be credited to all QSEs based on the Load Ratio Share for the relevant period.

[PRR676: Delete Section 6.6.3.2.1(9) above, upon system implementation.]

(10) RMR Units will be considered available to offset RPRS needs in resolving Local Congestion in the RPRS procurement process. The selection process will set a bid price for each RMR Unit based on its contract start and operational costs. If the optimal solution indicates an RMR Unit is a more economic option in resolving Local Congestion, the RMR Unit will be deployed and paid as an RMR deployment.

Generation Resources that are eligible for RPRS procurement that do not submit an RPRS bid will be considered in the RPRS procurement process. The selection process will set a bid price for each non-bid Generation Resource based on its generic cost times an adjustment factor. If the non-bid Generation Resource with an adjustment factor is a more economic option, the non-bid Generation Resource will be deployed and paid as an OOMC deployment.

(11) In the case of tied bids for the selection of RPRS, ERCOT will select the bid that meets the requirement most closely (achieving the optimal solution). When the price and capacity are identical from unaffiliated bidders, ERCOT may request re-bids.

(12) For RPRS, for each hour, for each Congestion Zone, ERCOT will post the quantity of capacity procured and the MCPCs and Shadow Prices.

6.6.3.3 ERCOT Emergency Ancillary Service Procurement

(1) Any ERCOT procurement of Ancillary Services in the Operating Period other than the deployment of Balancing Energy Service will be pursuant to Section 5, Dispatch.

(2) QSEs may not self-arrange for Ancillary Services procured in response to emergency situations.

6.6.4 Obligations to Honor Ancillary Services Commitments

The Ancillary Service Obligations from the schedule submitted prior to the close of the Adjustment Period are binding commitments of the QSE to ERCOT. If ERCOT issues Resource-specific OOME or Resource-specific Balancing Energy Dispatch Instructions to a QSE that causes the QSE to be unable to Supply its Ancillary Service Obligation(s), the ERCOT shall issue a verbal Dispatch Instruction that:

(1) Relieves that QSE from having to provide the specific Ancillary Service(s) for specific intervals and the reason or,

(2) Retracts the Dispatch given to the QSE so that the QSE may come back into compliance with their Ancillary Service Obligation(s).

6.6.5 Mandatory Provision of Ancillary Service Capacity to ERCOT

Notwithstanding any other provision in these Protocols, ERCOT may require a QSE to provide OOMC, OOME, or Zonal OOME Service Resources if necessary to avoid an ERCOT System insufficiency or system Emergency Condition. If required, ERCOT will procure these Ancillary Services in accordance with the requirements of OOMC, OOME, and Zonal OOME Services.

6.6.6 Provision of Multiple Ancillary Services from a Resource

An individual Resource may provide more than one Ancillary Service, provided that the sum of the Ancillary Service capacities committed to ERCOT, when added to the bilaterally scheduled level, is within the operating capability of the Resource as specified in the Resource Plan submitted by the QSE.

6.6.7 Insufficiency of Ancillary Services Bids

If ERCOT receives insufficient Ancillary Service bids to procure required Ancillary Services such that the Ancillary Services Plan is deficient and system security and reliability is threatened, ERCOT shall declare a market insufficiency Watch for the applicable Ancillary Service and will act in accordance with Section 5.6.5, Watch, to obtain adequate Resources to ensure reliability. If insufficiency is declared for a particular Ancillary Service in a specific hour, the market for that service for that hour is closed.

6.6.7.1 Procurement of Ancillary Services During Insufficiency

Upon declaration of market insufficiency, ERCOT will procure and/or arrange for additional capacity of the insufficient Ancillary Service for the affected hourly intervals. ERCOT will not accept any additional bids for the Ancillary Service for which market insufficiency has been declared. Compensation for capacity for Ancillary Services procured during market insufficiency and for subsequent procurement after the declaration of market insufficiency will be as per Section 6.8.1.1, Payments for Ancillary Services.

6.7 Deployment Policy

Energy from Ancillary Services may be deployed by ERCOT, only in the Operating Period, and only for reliability reasons in order to maintain frequency and system security. Energy will be deployed from Ancillary Services as prescribed by their specific function and may not be used to substitute for other services because of price except as permitted under 6.6.3.1 (10). ERCOT shall deploy all services other than Regulation in a minimum of one (1) Mw blocks.

6.7.1 Deployment of Balancing Energy

6.7.1.1 Creation of the Balancing Energy Bid Stack

(1) The Balancing Energy Service Bid Stack for the Operating Period will be created at the close of the Adjustment Period from the most recent Balancing Energy Service Up, Balancing Up Load, and Balancing Energy Service Down bids submitted by QSEs. QSEs can submit revised bids up to the close of the Adjustment Period.

(2) ERCOT may use varying amounts of Balancing Energy for each Settlement Interval as constrained by:

(a) The QSE-designated bid ramp rate limiting the amount of Balancing Energy Service that can be deployed in each fifteen (15) minute Settlement Interval for Balancing Energy Service Up or Down bids; or

(b) The QSE-designated block bid for Balancing Up Load.

(3) QSEs may designate the amount of Balancing Energy Service that can be deployed in each of the Settlement Interval by:

(a) Specifying a bid ramp rate effective for the whole hour. The limit for the hour is no less than the total amount bid by the QSE; and/or

(b) Designating the amount of Balancing Up Load that can be deployed by specifying blocks.

Ten minutes prior to crossing the hour boundary, ERCOT will evaluate the Balancing Energy previously awarded and re-deploy services based on specified bids for the new hour.

(4) QSEs may:

(a) Supply multiple price-quantity pair bids for Balancing Energy Service Up and Balancing Energy Service Down energy (i.e., "up and/or down curves") to ERCOT for each Congestion Zone; and/or

(b) Supply multiple block bids for Balancing Up Load Service to ERCOT for each Congestion Zone.

(5) The MCPE for each Settlement Interval for each Congestion Zone will be posted by ERCOT to the marketplace when energy is deployed or recalled. For Settlement Interval during which no Balancing Energy is deployed or recalled, the MCPE is the first (highest) Balancing Energy Service Down bid price for the interval.

(6) ERCOT will develop a forecast of Balancing Energy Service needed in each Settlement Interval.

(7) ERCOT's System Operator will not have access to individual bid prices or the expected MCPE if the next energy bid is selected. Rather, the Operator will deploy all or a portion of a bid, moving up and down the deployment energy stack. All bids will remain in one stack and the MCPE will be posted, unless there is Congestion. If energy stacks must be separated by Congestion Zone, because of Zonal Congestion, the MCPE of each zone will be posted.

(8) ERCOT will provide Notice to QSEs via the Messaging System of their awards for Balancing Energy Service, identifying awards that are for Balancing Up Load. QSEs will be required to respond with manual or electronic acknowledgement.

(9) ERCOT shall notify each QSE of its instructed amount of Balancing Energy Service ten (10) minutes prior to the Settlement Interval in which it is to be deployed. For Balancing Energy bid on Resources other than Balancing Up Loads, QSEs shall be expected to provide a power level during the Settlement Interval that will provide the instructed amount of Balancing Energy Service for that interval. For ERCOT Instructions to deploy Balancing Up Loads, the QSE shall be expected to provide the instructed amount of Service by interrupting Load. For ERCOT Instructions to deploy Balancing Up Loads from a QSE's Dynamically Scheduled Load, QSEs shall be expected to ensure that the generation following the Load is increased above the actual Dynamically Scheduled Load meter readings by the amount of the signal sent to ERCOT that is estimated in Real Time representing the real power interrupted in response to the deployment of Balancing Up Load (BUL). Deployment of energy as a result of adjustments in Dynamic Schedules to account for deployment of BUL will not be considered an Uninstructed Deviation.

(10) Any energy provided by a QSE in a Settlement Interval in which it has not been instructed to provide Balancing Energy Service by ERCOT will not set the MCPE, regardless of whether the energy provided was necessary for the QSE to meet ERCOT's instruction for a future or past Settlement Interval.

(11) A Load acting as a Resource has the option to request a Load bid to be deployed only as a complete block. To the extent that ERCOT deploys a bid by a Load acting as a Resource that has chosen a block deployment option, ERCOT shall either deploy the entire bid or,

if only partial deployment is possible, skip the bid by the Load acting as a Resource and proceed to deploy the next available bid.

6.7.1.2 Deployment of Balancing Energy when Congestion Occurs

(1) If the Operational Model indicates there is Zonal Congestion, ERCOT will separate the Balancing Energy Service bids into a Bid Stack for each Congestion Zone.

(2) ERCOT will use the Operational Model to determine the amount and location of Balancing Energy deployment for clearing Zonal Congestion as well as balancing the system.

(3) Except as stated in item (4) below, ERCOT will deploy Balancing Energy bids within a zone in bid price Merit Order.

(4) ERCOT may form specific Resource prices for both incrementing and decrementing a specific Resource to resolve Local Congestion.

(5) As part of the submittal of the Resource Plan for each Resource at a plant, QSEs may specify bid premiums by Resource. For each Resource, a submitted bid premium for Balancing Energy Up must be less than or equal to the Resource Category Generic Price for Balancing Energy Up deployments; the submitted bid premium for Balancing Energy Down must be greater than or equal to the Resource Category Generic Price for Balancing Energy Down deployments calculated pursuant to Section 4.4.20, Publication of Resource Category Bid Limits. With the exception of eligible non-bid Resources [as defined in item (6) below], if a bid premium is not specified in the Resource Plan, ERCOT will set the incremental bid premium equal to the Resource Category Generic bid limit for Balancing Energy Up and the decremental bid premium equal to the Resource Category Generic bid limit for Balancing Energy Down. Resource-specific incremental prices will be the incremental bid premium specified by the QSE based on the Resource Category Generic Price for Balancing Energy Up and the Resource-specific decremental prices will be the decremental premium specified by the QSE based on the Resource Category Generic Price for Balancing Energy Down.

(6) A QSE may specify within the Resource Plan that Renewable Resources, Qualifying Facilities, and Loads Acting as a Resource are "non-bid Resources." A QSE must specify an RMR unit, a hydroelectric unit, and a nuclear unit as a non-bid Resource. With the exception of hydroelectric and nuclear units, a non-bid Resource may be deployed automatically by the system as necessary to maintain reliability. To accomplish this, the system will set an incremental price for the non-bid Resources such that the pricing order from lowest to highest for deployment of Balancing Energy Up among the non-bid Resources will be as follows: RMR, Qualifying Facility, Renewable, Load Acting as a Resource. The system will set a decremental price for the non-bid Resources such that the pricing order from lowest to highest for deployment of Balancing Energy Down among the non-bid Resources will be as follows: Renewable, Qualifying Facility, RMR.

(7) The actual Shift Factors with respect to the Local Congestion of Resources' individual incremental and decremental prices from above are used to determine the most economical deployment of individual Resources to solve Local Congestion.

(8) ERCOT will instruct QSEs to deploy Balancing Energy Service from a specific Resource through the issuance of a Dispatch Instruction for each Resource using the most economical solution to resolve the Local Congestion.

(9) The Dispatch Instruction will specify the instructed output level, the amount of Balancing Energy Service, and the range of acceptable operation of the specific Resource.

(10) For an incremental Resource-specific instruction, the QSE will be paid in accordance with Section 7.4.3.1, Balancing Energy Up from a Specific Resource.

(11) For a decremental unit-specific Dispatch Instruction, the QSE will be paid in accordance with Section 7.4.3.2, Balancing Energy Down from a Specific Resource.

(12) QSEs shall first meet the specific Resource deployment performance requirements of Section 6.10.7, Individual Resource Dispatch Performance, and then provide the Balancing Energy Service deployment instructed pursuant to Section 6.7.1, Deployment of Balancing Energy. In the event that a QSE is unable to provide the Balancing Energy Service due to a specific Resource deployment then the QSE will follow the Notification procedures established in Section 5, Dispatch.

(13) If a Resource is specified as a non-bid Resource, then ERCOT will use OOME to determine the amount paid to the QSE in connection with the Resources dispatched to resolve the constraint.

(14) The QSEs providing Balancing Energy Service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Service Deployment Measures.

(15) ERCOT shall not automatically redeploy nuclear and hydroelectric units using the ERCOT Systems that analyze and resolve transmission Congestion. ERCOT shall only redeploy nuclear and hydroelectric units manually through the use of a verbal Dispatch Instruction if there is no reasonably practicable Resource solution to Congestion available.

6.7.1.3 Deployment of Balancing Energy During Unusual Events

(1) During Unusual Events such as major frequency disturbances greater than 0.05 Hz and unexpected significant Load changes greater than half the amount of Regulation Service purchased in either direction, ERCOT may deploy Balancing Energy so as to mitigate the consequences of the Unusual Event. During such an Event, ERCOT may take one (and only one) the following actions:

(a) Recall Balancing Energy Up Instruction(s) or a Balancing Energy Down Instruction(s) before the fifteen (15) minute Settlement Interval is complete or without the ten (10) minute notice. There is no change to the MCPE in the Settlement Interval for this action. If ERCOT exhausts all recall options, it may deploy unit-specific Balancing Energy based on unit-specific premiums. The cost of these premiums will be charged to the Balancing Energy Neutrality Adjustment set forth in Section 9.6.1, Balancing Energy Neutrality Adjustment, of these Protocols.

(b) Deploy Balancing Energy in the same direction as the immediately previous Instruction without the ten (10) minute notice for the remaining of the current Settlement Interval. For this action, ERCOT must modify the MCPE for the Settlement Interval to the highest price deployed for additional Balancing Energy Up or the lowest price deployed for additional Balancing Energy Down.

6.7.2 Deployment of Regulation Service

(1) RGS will be deployed in response to a change in ERCOT System frequency to maintain that frequency within predetermined limits. Deployment will be accomplished through use of an automatic signal from ERCOT to each QSE provider of RGS.

(2) Dispatch Instructions for regulation capacity will be deployed on a proportional basis, given the ratio of capacity provided, among providers of that capacity having been scheduled for the service.

(3) ERCOT is required to minimize the use of RGS energy as much as practicable by operating its automatic generation control system in conjunction with deploying Balancing Energy with the objective that Regulation Service Up energy and Regulation Service Down energy are deployed in each Settlement Interval.

(4) Energy deployed under RGS will not be accounted for separately, but will be settled at the MCPE for Balancing Energy.

(5) ERCOT shall integrate the control signal sent to providers of Regulation Service Up thus calculating the amount of energy deployed in each Settlement Interval.

(6) ERCOT shall integrate the control signal sent to providers of Regulation Down Service and calculate the amount of energy deployed in each Settlement Interval.

(7) ERCOT shall post to all Market Participants the total amount of deployed Regulation Service Up and Regulation Service Down energy in each Settlement Interval of the previous hour.

(8) QSEs providing Regulation Service shall provide a feedback signal to ERCOT via the MDAS that identifies the amount of regulation energy being provided each control cycle.

(9) For each QSE providing RGS the implied ramp rate in megawatts per minute is the total amount of Regulation Service awarded divided by ten (10).

(10) The QSEs providing RGS shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Service Deployment Performance Measures.

6.7.3 Deployment of Responsive Reserve Service

(1) Responsive Reserve energy shall be deployed as necessary to meet North American Electric Reliability Corporation (NERC) requirements. This shall be accomplished by:

(a) Automatic Resource control/governor system action as a result of a significant frequency deviation;

(b) Through use of an automatic signal and a Dispatch Instruction to deploy Responsive Reserve energy from Resources; and/or

(c) By Dispatch Instructions for deployment of Responsive Reserve energy from interruptible Load acting as a Resource via an electronic Messaging System to providers.

(2) Deployment of energy as a result of automatic Resource control/governor system action will not be considered as an Uninstructed Deviation.

(3) ERCOT will deploy Responsive Reserve Service (RRS) in response to disturbance control assistance requirements as specified in the Operating Guides or after all the bids in the Balancing Energy Services Up Bid Stack have been depleted. Energy from Responsive Reserve Resources will be deployed by ERCOT in accordance with Section 5.6, Emergency and Short Supply Operation.

(4) ERCOT deployment of RRS Resources will be proportioned first between suppliers who provide RRS using Generation Resources until thirty-three percent (33%) of the total amount procured by ERCOT is deployed. If deployment of more than thirty-three percent (33%) is required, ERCOT shall:

(a) For frequency restoration caused by an event other than capacity insufficiency, issue an Emergency Notice for frequency restoration and deploy all or a portion of remaining RRS being provided by hydro Resources and by Loads acting as Resources (LaaRs).

(b) For frequency restoration related to capacity insufficiency, declare the Energy Emergency Alert (EEA) in effect and follow emergency provisions in Section 5, Dispatch.

(5) ERCOT will deploy Balancing Energy Service and Non-Spinning Service as soon a practicable to minimize the use of Responsive Reserve energy.

(6) All providers of Responsive Reserve Resources will be required to provide feedback to ERCOT of their availability and level of deployment in Real Time. Except in those instances where a significant frequency deviation has occurred and temporary

deployment is necessary to meet NERC requirements, ERCOT shall deploy RRS according to Section 5.6.

(7) Once RRS is deployed, the obligation to deliver energy shall remain until specifically instructed by ERCOT to stop providing energy from RRS, but not longer than the period of the service is scheduled.

(8) The QSEs providing RRS shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Service Deployment Performance Measures.

[PRR496: Add paragraph (9) below to Section 6.7.3 upon system implementation.]

(9) RRS procured from a LaaR block bid shall be deployed as a block.

6.7.4 Deployment of Non-Spinning Reserve Service

(1) ERCOT shall deploy 30-Minute Non-Spinning Reserve Service (30MNSRS) when it expects Balancing Energy Services to be depleted but not before it predicts more than ninety-five percent (95%) of the Balancing Energy Service Up available, including Balancing Energy Service Up bids representing BES-Capable Non-Spinning Reserve Service (BESCNSRS), for the Operating Hour will be deployed.

(2) ERCOT shall deploy BESCNSRS capacity that is represented by Balancing Energy Service bids as Balancing Energy Service.

(3) ERCOT may, in its sole judgment, deploy 30MNSRS as necessary.

(4) Deployment of 30MNSRS Resources will be proportioned among suppliers.

(5) 30MNSRS deployment or recall instructions by ERCOT are not constrained by any ramp rate. However, the QSE is expected to deploy or recall those instructions at a ramp rate that would comply to the instruction in thirty (30) minutes. During a period of 30MNSRS deployment, all energy provided by the QSE responding to the Non-Spinning Reserve Service (NSRS) deployment will be considered instructed.

(6) Energy from 30MNSRS capacity may be deployed in a Congestion Zone by ERCOT if, in its judgment, not enough Balancing Energy Service Up is available to satisfy reliability needs.

(7) ERCOT will provide Notice via the Messaging System to QSEs of their Obligations for NSRS energy as the QSE's Resources are selected. Providers will be required to respond with manual or electronic acknowledgement. Simultaneously with the posting of MCPE, ERCOT will post Non-Spin deployment amounts and locations to the Market Information System (MIS).

(8) All providers of 30MNSRS Resources will provide Notification to ERCOT of their availability and level of deployment.

(9) Once 30MNSRS is deployed, the Obligation to deliver energy will remain until ordered to stop providing by ERCOT (after not less than one (1) hour), but not longer than the period of the service is scheduled.

(10) 30MNSRS may be deployed at any time in a Settlement Interval.

(11) The QSEs providing 30MNSRS shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Service Deployment Performance Measures.

[PRR496: Add (12) to Section 6.7.4 as follows when system change implemented.]

(12) NSRS procured from a LaaR Block Bid shall be deployed as a block.

6.7.5 Deployment of Replacement Reserve Service

(1) All units selected to supply this service based on capacity bids will have their Balancing Energy Service bid associated with the service placed in the Balancing Energy Service Bid Stack and will be deployed in accordance with these Protocols.

(2) Replacement Reserve Service providers are required to provide incremental Balancing Energy Service bids as specified in Section 6.4.2, Determination of ERCOT Control Area Requirements, item (5). Energy bids from Replacement capacity reserves will be treated as any other incremental energy bid.

(3) The QSEs providing Replacement Reserve Service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Service Deployment Performance Measures.

6.7.6 Deployment of Voltage Support Service

(1) ERCOT, or TSPs designated by ERCOT, will instruct Generation Resources required to provide VSS to make adjustments for voltage support within the URL capacity limits provided by the QSE to ERCOT. Generation Resources providing VSS will not be requested to reduce megawatt output so as to provide additional megavolt-amperes reactive, nor will they be requested to operate on a voltage schedule outside the Unit Reactive Limits (URL) specified by the QSE without a Dispatch Instruction requesting unit-specific Dispatch or an OOME instruction.

(2) ERCOT and TDSPs shall develop operating procedures specifying Voltage Profiles of transmission controlled reactive Resources to minimize the dependence on generation-supplied reactive Resources. For Generation Resources required to provide VSS, step-up

transformer tap settings will be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

(3) The TSP, under ERCOT direction, is responsible for monitoring and ensuring that all Generation Resources required to provide VSS dynamic reactive sources in a local area are deployed in approximate proportion to their respective installed reactive capability requirements.

(4) All Generation Resources required to provide VSS shall maintain the transmission voltage at the point of interconnection to the transmission grid as directed by ERCOT within the operating Reactive Power capability of the unit(s).

(5) At all times a Generation Resource unit required to provide VSS is On-line, the URL must be available for utilization at the generating unit's continuous rated active power output, and Reactive Power up to the unit's operating capability must be available for utilization at lower active power output levels. In no event shall the Reactive Power available be less than the required installed reactive capability multiplied by the ratio of the lower active power output to the generating unit's continuous rated active power output, and any Reactive Power available for utilization must be fully deployed to support system voltage upon request by ERCOT, or a TSP.

(6) The QSEs providing Voltage Support Service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Service Deployment Performance Measures.

6.7.7 Deployment of Out-of-Merit Energy Service

Deployment of units for OOME Service will follow Balancing Energy Service deployment guidelines as specified in Section 5, Dispatch.

6.7.7.1 Deployment of Fleet/Zonal OOME

(1) During circumstances when command and control actions are required, ERCOT may instruct one or more specific QSEs to adjust their total ERCOT generation level or their generation level in a specific Congestion Zone (Zonal) or across all zones (Fleet). The Dispatch Instruction includes the quantity of energy required and the Congestion Zone(s), if applicable, but does not specify which Generation Resource(s) the QSE(s) should move. Such a Dispatch Instruction will be referred to as a "Fleet/Zonal OOME Dispatch Instruction."

(2) A Fleet/Zonal OOME Dispatch Instruction will be treated as an instructed deviation for Settlement purposes. When ERCOT issues a Fleet/Zonal OOME Dispatch Instruction, the resulting instructed deviation from the Fleet/Zonal OOME Dispatch Instruction will be defined by the MW amount as specified in the Fleet/Zonal OOME Dispatch Instruction.

(3) A Fleet/Zonal OOME Dispatch Instruction will be included in the calculation of the SCE. The Dispatch Instruction will not be constrained by ramp rate; therefore, the change will be considered a step change.

(4) ERCOT will send Fleet/Zonal OOME Dispatch Instructions to QSEs concurrent with Balancing Energy Service Dispatch Instructions for the target interval.

[PRR 422: Replace (4) above with the following when the system changes are implemented.]

(4) For manual deployment of Fleet/Zonal OOME before market clearing, the instructed deviation will be balanced using the Balancing Energy Service Bid Stack. ERCOT will send Fleet/Zonal OOME Dispatch Instructions to QSEs concurrent with Balancing Energy Service Dispatch Instructions for the target interval. The Balancing Energy Service deployment will be limited by the constraints imposed by the Fleet/Zonal OOME Dispatch Instructions. The instructed deviations for these Fleet/Zonal OOME Dispatch Instructions will be included in the Balancing Energy Service Dispatch Instructions for that QSE for the target interval. For the Fleet/Zonal OOME Dispatch Instructions, ERCOT will endeavor to honor the Fleet/Zonal portfolio ramp rate as indicated in the QSE's Zonal Balancing Energy Service Bids.

6.7.7.2 Deployment of Resource-Specific OOME Before Market Clearing

When ERCOT issues a Resource-specific OOME Dispatch Instruction before the Balancing Energy Service market clears, the instructed deviation resulting from the OOME Dispatch Instruction will be defined as the difference between the instructed output level in the Dispatch Instruction and the Resource Plan output level when the Balancing Energy market clearing engine is initiated for the target service interval except: 1) A Resource is instructed to operate at or above an instructed output level and the planned output level of that Resource is above the instructed output level, or 2) A Resource is instructed to operate at or below an instructed output level and the planned output level of that Resource is below the instructed output level. The instructed deviation will be balanced using the Balancing Energy Service Bid Stack. ERCOT will send OOME Dispatch Instructions to QSEs concurrent with Balancing Energy Service Dispatch Instructions for the target interval. The Balancing Energy Service deployment will be limited by the constraints imposed by the OOME Dispatch Instructions. The instructed deviations for these OOME Dispatch Instructions will be included in the Balancing Energy Service Dispatch Instructions for that QSE for the target interval. ERCOT must honor the unit ramp rates set forth in the QSE's Resource Plan for the applicable Generation Resource.

6.7.7.3 Deployment of OOME After Market Clearing

Resource-specific OOME Dispatch Instructions issued after the Balancing Energy Service market clears will not be instructed deviations. ERCOT will use its best efforts to minimize Resource-specific OOME and Fleet/Zonal OOME Dispatch Instructions issued after the Balancing Energy Service market has cleared.

6.7.7.4 Out of Merit Energy to Zero (0) MW

When ERCOT issues an OOME Dispatch Instruction to a Resource to operate at a level lower than the Resource's Low Operating Limit, ERCOT will instruct such Resource down to zero (0) MW for at least the period of the Resource Minimum Down Time.

[PRR454: Replace Section 6.7.7.4 with the following upon system implementation]

When ERCOT issues an OOME Dispatch Instruction to a Resource to operate at a level lower than the Resource's Low Operating Limit, ERCOT will instruct such Resource down to zero (0) MW for at least the period of the Resource Minimum Down Time. The instructed Resource will be paid OOME as well as a single Resource Category Generic Startup Cost if the Resource is recalled and does start during a period it would have been scheduled On-line in its Resource Plan.

6.7.8 Deployment of RMR Service

(1) If a bid-based solution is not available and in Emergency Conditions, ERCOT shall have the option to Dispatch a contracted RMR Unit at any time for voltage support or localized transmission limitations, but it must Dispatch the unit as early as possible (if conditions merit) once conditions are identified that require the use of the RMR Unit and only to the extent of megawatt loading necessary to correct the voltage support or localized transmission limitation.

(2) ERCOT must elect to use Resources under an RMR Agreement or MRA Agreement before issuing an OOME or Zonal OOME Dispatch Instruction subject to the terms of the Agreement, if practical.

(3) ERCOT will deploy RMR Units in accordance with the RMR Agreement and MRA Resources in accordance with the MRA Agreement. RMR Agreements with ERCOT are expected to include limitations on the total service hours, megawatt-hour output, and the number of starts available to ERCOT for each RMR Unit.

(4) ERCOT shall issue Dispatch Instructions via the Messaging System for any RMR Unit Dispatch or MRA Resource Dispatch. Any revisions to those instructions must be communicated via revised Dispatch Instructions.

(5) In the event that ERCOT orders an RMR Unit or MRA Resource to operate to sustain reliable ERCOT System operation in any Operating Day, ERCOT will post on the MIS as soon as possible, but no later than the next Business Day, for such Operating Day:

  (a) Each Resource receiving an RMR or MRA Dispatch Instruction for each interval;

  (b) The amount of RMR or MRA energy ERCOT requested from each Resource for each interval; and

(c) The binding transmission constraint (contingency and/or overloaded element(s)) causing RMR or MRA deployments.

(6) If ERCOT orders an RMR Unit or MRA Resource to operate to sustain reliable ERCOT System operation in any Operating Day, ERCOT will, on or before the Business Day following the day of issuance of the Initial Statement for the Operating Day on which ERCOT issued the Dispatch Instruction, as described in Section 9.2.3, Initial Statements, post on the MIS the amount of RMR or MRA energy actually provided by each RMR or MRA Unit for each interval of the subject Operating Day.

(7) ERCOT shall publicly post an annual forecast of the Dispatch pattern it expects for each contracted RMR Unit and MRA Resource as well as monthly and week-ahead forecasts regarding its use of such Resources.

(8) ERCOT will adjust the amount of Balancing Energy acquired due to the impact of RMR Energy deployed and energy deployed from MRA Resources. If adjustments made by ERCOT would result in the QSE exceeding its scheduled amount of generation, then the affected QSE must not accommodate these changes by adjusting other Resources such that the Schedule Control Error is minimized. ERCOT will not assess URC charges to the QSE as a result of these adjustments for the interval. The RMR may implement a Responsibility Transfer between its QSE and ERCOT for energy delivered under an RMR Agreement to minimize the impact of RMR scheduling on its QSE.

6.7.9 Deployment of Emergency Interruptible Load Service (EILS)

(1) EILS shall be deployed by ERCOT via verbal Dispatch Instruction in a single phone call to all QSEs providing EILS. A QSE representing available contracted EILS Resources shall instruct the EILS Resources to curtail Load consistent with their commitments.

(2) When ERCOT deploys EILS, it shall deploy all contracted EILS Resources.

(3) ERCOT shall deploy EILS only as defined in Section 5.6.7, EEA Levels.

(4) EILS may be deployed at any time in a Settlement Interval.

(5) Once ERCOT has deployed EILS, EILS Resources shall remain reduced until ERCOT specifically releases the EILS deployment via a verbal Dispatch Instruction to the all-QSE hotline.

(6) Unless scheduled to go Off-line, due either to an EILS Time Period transition or a previously scheduled period of unavailability, an EILS Resource deployed for EILS shall return to its committed operating level as soon as practical following an ERCOT recall verbal Dispatch Instruction and shall have a maximum of ten (10) hours to do so.

6.8 Compensation for Services Provided

This section of the Protocols provides a summary of Ancillary Service payments.

6.8.1 Payments to Providers of Ancillary Services Procured in the Day Ahead and Adjustment Periods

Payments to Providers of Regulation Down, Regulation Up, Responsive Reserves, Non-Spinning Reserves, and Replacement Reserves and Balancing Energy are as described below.

6.8.1.1 Payments for Ancillary Service Capacity

(1) A QSE whose bid to provide an Ancillary Service Resource to ERCOT is accepted in a particular market in ERCOT's Day-Ahead and Adjustment Period Ancillary Service procurement process shall be paid for services other than RPRS the amount (in megawatts) of Ancillary Service capacity accepted by ERCOT in that market, multiplied by the MCPC in that market for the Operating Hour.

(2) During periods of insufficient bids for Ancillary Service markets for RGS, RRS, and NSRS, the following shall apply:

(a) A QSE whose bid to provide an Ancillary Service Resources has been awarded, shall be paid the amount (in megawatts) of Ancillary Service capacity accepted by ERCOT, multiplied by the MCPC for the Ancillary Service by hour.

(b) A QSE called upon by ERCOT to provide an Ancillary Service Resource after market insufficiency has been declared, excluding previously accepted bids, shall be paid the amount (in megawatts) of the Ancillary Service capacity called for by ERCOT multiplied by the MCPC that would have resulted if ERCOT had procured only eighty percent (80%) of the capacity procured prior to declaration of insufficiency, for that particular Ancillary Service.

(3) A QSE whose bid to provide a RPRS Resource to ERCOT is accepted for capacity insufficiency or Zonal Congestion management in ERCOT's Adjustment Period procurement process shall be paid in accordance with the Zonal Replacement Reserve formula in Section 6.8.1.10, Zonal or System Wide Replacement Reserve Service Capacity Payment to QSE.

(4) A QSE whose bid to provide a RPRS Resource to ERCOT is accepted for the purpose of Local Congestion management in ERCOT's Adjustment Period procurement process shall be paid in accordance with the Local Replacement Reserve formula in Section 6.8.1.11, Local Congestion Replacement Reserve Payment to QSE.

6.8.1.2 Regulation Up Service Payment to QSE

A QSE whose bid to provide a Regulation Up Service to ERCOT is accepted in ERCOT's Ancillary Service procurement process shall be paid for the service as follows:

$$\mathbf{PC_{RUqim} = -1 * C_{RUqim} * MCPC_{RUim}}$$

The equation below will be used to determine the Total Regulation Up Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PC_{RUi} = \Sigma\ (\Sigma\ (PC_{RUqim})_q)_m$$

Where:

i	interval being calculated
m	Procurement for market, m, of the Day Ahead and Adjustment Period
PC_{RUqim}	Regulation Up Payment for that interval Procured Capacity for Regulation Up Reserve Payments ($) for that interval for that QSE determined for market, m.
PC_{RUi}	Procured Regulation Up Capacity Costs ($) for the Total Market for the interval
C_{RUqim}	Awarded Regulation Up Service Capacity (MW) in the market, m, per interval for that QSE
$MCPC_{RUim}$	The Regulation Up Reserve Market Clearing Price of Capacity Costs ($/MW) per interval of market, m.

6.8.1.3 Emergency Short Supply Regulation Up Capacity Payment to QSE

(1) Develop a composite Bid Stack containing all bids for Regulation Up Service in the interval.

(2) Establish the capacity quantity of Megawatts purchased in that interval, in accordance with Section 6.8.1.1, Payments for Ancillary Service Capacity.

(3) Determine the price as if only eighty percent (80%) of the procured Regulation Up capacity were purchased in that interval. This becomes the derived price to be used in settlement of Emergency Regulation Up Service, as described below.

(4) Emergency Short Supply Regulation Up Capacity will be allocated to Load as part of the Regulation Up Load Allocation.

Emergency Short Supply Regulation Up Capacity Payment will be calculated as follows:

$$\mathbf{PCI_{ESRUqi} = -1 * (DP_{RUi} * C_{ESRUqi})}$$

The equation below will be used to determine the Total Regulation Up Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PCI_{ESRUi} = SUM\ (PCI_{ESRUqi})_q$$

Where:

i	interval
PCI_{ESRUqi}	Procured Emergency Capacity Payment for that QSE when insufficient bids for Regulation Up were received for that interval.
PCI_{ESRUi}	Emergency Short Supply Regulation Up Capacity Costs ($) for the total Market for the interval
DP_{RUi}	Derived Price ($/MW) of the Ancillary Service that had insufficient bids. (The price, which would have resulted if only eighty percent (80%) of the Regulation Up capacity that was initially bid was awarded).
C_{ESRUi}	Regulation Up Capacity (MW) procured from that QSE due to insufficient bids of that service

6.8.1.4 Regulation Down Service Payment to QSE

A QSE whose bid to provide an Regulation Down Service to ERCOT is accepted in ERCOT's Ancillary Service procurement process shall be paid for the service as follows:

$$\mathbf{PC_{RDqim} = -1 * C_{RDqim} * MCPC_{RDi}}$$

The equation below will be used to determine the Total Regulation Down Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PC_{RDi} = \text{SUM (SUM } (PC_{RDqim})_q)_m$$

Where:

i:	interval being calculated
m:	Procurement for market, m, of the Day Ahead and Adjustment Period.
PC_{RDqim}:	Regulation Down Payment per interval Procured Capacity for Regulation Down Payments ($) per interval for that QSE determined for market, m.
PC_{RDi}:	Procured Regulation Down Capacity Costs ($) for the Total Market for the interval
C_{RDqim}:	Awarded Regulation Down Service Capacity (MW) in the market, m, per interval for that QSE.
C_{ARDqi}	Awarded Regulation Down Service Capacity (MW) in the Adjustment Market per interval for that QSE
$MCPC_{RDim}$:	The Regulation Down Service Market Clearing Price of Capacity Costs ($/MW) per interval for market, m.

6.8.1.5 Emergency Short Supply Regulation Down Service Capacity Payment to QSE

(1) Develop a composite Bid Stack containing all bids for Regulation Down Service in the interval.

(2) Establish the capacity quantity of Megawatts purchased in that interval, in accordance with Section 6.8.1.1, Payments for Ancillary Service Capacity.

(3) Determine the price as if only eighty percent (80%) of the procured Regulation Down capacity were purchased in that interval. This becomes the derived price to be used in settlement of Emergency Short Supply Regulation Down Service, as described below.

(4) Emergency Short Supply Regulation Down Service Capacity will be allocated to Load as part of the Regulation Down Load Allocation.

Emergency Short Supply Regulation Down Service Capacity Payment will be calculated as follows:

$$\mathbf{PCI_{ESRDqi} = -1 * (DP_{RDi} * C_{ESRDqi})}$$

The equation below will be used to determine the Total Regulation Down Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PCI_{ESRDi} = \Sigma\ (PCI_{ESRDqi})_q$$

Where:

i	interval
PCI_{ESRDqi}	Procured Emergency Short Supply Service Capacity Payment for that QSE when insufficient bids for Regulation Down were received for that interval.
$PCI_{ESRDi:}$	Emergency Short Supply Service Regulation Down Capacity Costs ($) for the total Market for the interval
DP_{RDi}	Derived Price ($/MW) of the Ancillary Service had insufficient bids, (the price which would have resulted if only eighty percent (80%) of the Regulation Down capacity that was initially supplied was awarded).
C_{ESRDqi}	Emergency Short Supply Regulation Down Service Capacity (MW) from that QSE procured due to insufficient bids of that service

6.8.1.6 Responsive Reserve Service Payment to QSE

A QSE whose bid to provide an Responsive Reserve Service to ERCOT is accepted in ERCOT's Ancillary Service procurement process shall be paid for the service as follows:

$$\mathbf{PC_{RRqim} = -1 * C_{RRqim} * MCPC_{RRim}}$$

The equation below will be used to determine the Total Responsive Reserve Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PC_{RRi} = \text{SUM}\ (\text{SUM}\ (PC_{RRqim})_q)_m$$

Where:

i	interval being calculated
m	Procurement for market, m, of the Day Ahead and Adjustment Period.
PC_{RRqim}	Responsive Reserve Service Payment per interval Procured Capacity for Responsive Reserve Payments ($) per interval for that QSE determined for market, m.
PC_{RRi}	Procured Responsive Reserve Capacity Costs ($) for the Total Market for the interval
C_{RRqim}	Awarded Responsive Reserve Service Capacity (MW) in the market, m, per interval for that QSE
$MCPC_{RRi}$	Responsive Reserve Market Clearing Price of Capacity Costs ($/MW) per interval for market, m.

6.8.1.7 Emergency Short Supply Responsive Reserve Service Capacity Payment to QSE

(1) Develop a composite Bid Stack containing all bids for Responsive Reserve Service in the interval.

(2) Establish the capacity quantity of Megawatts purchased in that interval, in accordance with Section 6.8.1.1, Payments for Ancillary Service Capacity.

(3) Determine the price as if only eighty percent (80%) of the procured Responsive Reserve capacity were purchased in that interval. This becomes the derived price to be used in settlement of Emergency Responsive Reserve Service, as described below.

(4) Emergency Short Supply Responsive Reserve Service Capacity will be allocated to Load as part of the Responsive Reserve Load Allocation.

Emergency Short Supply Responsive Reserve Service Capacity Payment will be calculated as follows:

$$\mathbf{PCI_{ESRRqi} = -1 * (DP_{RRi} * C_{ESRRqi})}$$

The equation below will be used to determine the Total Responsive Reserve Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PCI_{ESRRi} = SUM(PCI_{ESRRqi})_q$$

Where:

i	interval
PCI_{ESRRqi}	Procured Emergency Service Responsive Reserve Capacity Payment for each QSE when insufficient bids for Responsive Reserve were received in that interval.
PCI_{ESRRi}	Emergency Short Supply Responsive Reserve Capacity Costs ($) for the total Market for the interval

DP_{RRi}	Derived Price ($/MW) of the Ancillary Service that had insufficient bids, (the price which would have resulted if only eighty percent (80%) of the Responsive Reserve capacity that was initially bid was awarded).
C_{ESRRqi}	Emergency Short Supply Responsive Reserve Capacity (MW) from that QSE procured due to insufficient bids of that service

6.8.1.8 Non-Spinning Reserve Service Payment to QSE

A QSE whose bid to provide an Non-Spinning Reserve Service to ERCOT is accepted in ERCOT's Ancillary Service procurement process shall be paid for the service as follows:

$$\mathbf{PC_{NSqim} = -1 * C_{NSqim} * MCPC_{NSim}}$$

The equation below will be used to determine the Total Non-Spinning Reserve Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PC_{NSi} = SUM\ (SUM\ (PC_{NSqim})_q)_m$$

Where:

i:	interval being calculated
m:	Procurement for market, m, of the Day Ahead and Adjustment Period.
PC_{NSqim}:	Procured Capacity for Non-Spinning Reserve Payments ($) for that interval for that QSE determined for market, m.
PC_{NSi}:	Procured Non-Spinning Reserve Capacity Costs ($) for the Total Market for the interval
C_{NSqim}:	Awarded Non-Spinning Reserve Service Capacity Quantity (MW) in the market, m, per interval for that QSE Service
$MCPC_{NSim}$:	Non-Spinning Reserve Service Market Clearing Price of Capacity Costs ($/MW) per interval of market, m.

6.8.1.9 Emergency Short Supply Non-Spinning Reserve Service Capacity Payment to QSE

(1) Develop a composite Bid Stack containing all bids for Non-Spinning Reserve Service in the interval.

(2) Establish the capacity quantity of Megawatts purchased in that interval, in accordance with Section 6.8.1.1, Payments for Ancillary Service Capacity.

(3) Determine the price as if only eighty percent (80%) of the procured Non-Spinning Reserve capacity were purchased in that interval. This becomes the derived price to be used in settlement of Emergency Non-Spinning Reserve Service, as described below.

(4) Emergency Short Supply Non-Spinning Reserve Service Capacity will be allocated to Load as part of the Non-Spinning Reserve Load Allocation.

Emergency Short Supply Non-Spinning Reserve Service Capacity will be calculated as follows:

$$\mathbf{PCI_{ESNSqi} = -1 * (DP_{NSi} * C_{ESNSqi})}$$

The equation below will be used to determine the Total Non-Spinning Reserve Service Payment to be allocated to each QSE as described in Section 6.9.1, Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods.

$$PCI_{ESNSi} = SUM\ (PCI_{ESNSqi})_q$$

Where:

i	interval
PCI_{ESNSqi}	Procured Emergency Short Supply Service Non-Spinning Capacity Payment for that QSE when insufficient bids for Non-Spinning were received in that interval.
PCI_{ESNSi}	Emergency Short Supply Service Non-Spinning Capacity Costs ($) for the total Market for the interval
DP_{NSi}	Derived Price ($/MW) of the service when the Ancillary Service that had insufficient bids. (The price, which would have resulted if only eighty percent (80%) of the Non-Spinning capacity bids that were initially bid, were awarded).
C_{ESNSqi}	Non-Spinning Capacity (MW) from that QSE procured due to insufficient bids of that service

6.8.1.10 Zonal or System Wide Replacement Reserve Service Capacity Payment to QSE

A QSE whose unit bid to provide RPRS to ERCOT is accepted in ERCOT's Ancillary Service procurement process shall be paid for services in the amount (in MW) of RPRS capacity accepted by ERCOT, multiplied by the maximum of the bid price or the highest MCPC of that interval per zone of all the RPRS procurement processes for a single Operating Hour, excluding any RPRS procured to resolve Local Congestion and is paid as follows:

$$\mathbf{PC_{RPqi} = SUM\ (PC_{RPqiuz})_u}$$

Given:

$$PC_{RPqiuz} = -1 * Max(PABC_{RPiu}, MCPC_{RPiz})* ZC_{RPqiuz}$$
$$PABC_{RPiu} = CBP_{RPiu}/N + HOBP_{RPiu}$$

Where:

i	interval being calculated

z	zone
u	single Resource
N	Number of hours that this Resource is continuously procured
CBP_{RPiu}	Capacity bid price submitted by the QSE for the single Resource
$HOBP_{RPiu}$	Hourly operational bid price submitted by the QSE for the single Resource
$MCPC_{RPiz}$	Highest Replacement Reserve Service Market Clearing Price of all procurement processes of Capacity ($/MW) per interval per zone, excluding any RPRS procured to resolve Local Congestion
$PABC_{RPiu}$	Bid Price of the single Resource awarded Replacement Reserve in that interval
PC_{RPqiuz}	Replacement Reserve Service Payments ($) by Resource per interval for that QSE
PC_{RPqi}	Replacement Reserve Payments ($) Service Payment per interval for that QSE
ZC_{RPqiuz}	Accepted Unit Adjustment Replacement Reserve Service Capacity Quantity (MW) to solve insufficiency or Zonal Congestion per interval per zone per QSE per single Resource.

The equation below will be used to determine the Total Replacement Reserve Payment to be allocated to each QSE as described in Section 6.9.2, QSE Obligations for Capacity Services Obtained in the Adjustment Periods.

$$PC_{RPi} = \text{SUM}\,(PC_{RPqi})_q$$

Where:

i	interval being calculated
q	QSE
PC_{RPqi}	Replacement Reserve Payments ($) Service Payment per interval for that QSE
PC_{RPi}	Summation of Replacement Reserve Payments ($) per interval for all QSEs in the market

6.8.1.11 Local Congestion Replacement Reserve Payment to QSE

(1) The QSE for a Resource selected to provide RPRS to resolve Local Congestion that actually reconnects to the ERCOT Transmission Grid and starts the unit in order to provide RPRS will be paid both the Resource Category Generic Startup Cost for starting the unit and the Resource Category Generic Minimum Energy Cost less the Market Clearing Price for Energy (MCPE) for operating at the Low Sustainable Limit (LSL) as set forth in the Resource Plan for that unit during the instructed interval(s). If the MCPE during the intervals of an hour in which ERCOT deploys a Resource for RPRS provides revenue in excess of the hourly cost to start and operates the unit at LSL, the QSE representing the Resource may retain any such excess revenue.

(2) Resources that are connected to the ERCOT Transmission Grid when the QSE is instructed to provide RPRS to resolve Local Congestion will be paid the Resource

Category Generic Minimum Energy Cost less the MCPE for operating at the LSL of the Resource during the instructed interval(s).

(3) If ERCOT instructs a QSE to provide RPRS from a Resource to resolve Local Congestion and the payment for RPRS does not cover the cost of providing the RPRS plus a ten percent (10%) premium, then that QSE may submit additional verifiable costs directly attributable to the RPRS Dispatch Instruction, which exceed the payment for RPRS calculated pursuant to paragraph (4) below. The QSE will be paid only for additional costs directly attributable to the RPRS Instruction, plus the premium. Verifiable costs are subject to the approved documentation requirements in paragraph (3)(h) below. The premium to be provided shall be the product of the costs of providing the service times ten percent (10%). However, the premium will not apply to the nodal implementation surcharge defined in Section 9.7.6, ERCOT Nodal Implementation Surcharge. Verification of these costs must be submitted to ERCOT by the QSE or the Resource to allow resolution by the end of the dispute process for Settlement True-Up as defined in Section 9.2.6, True-Up Statement.

(a) After receiving the Initial Statement for the subject Operating Day, the QSE shall submit a settlement dispute in accordance with the dispute process outlined in Section 9.5, Settlement and Billing Dispute Process. In addition to the standard information required on the dispute form on the ERCOT Portal, the dispute should clearly indicate:

(i) The Dispatch Instruction received from ERCOT to provide the RPRS;

(ii) The payment received for providing the RPRS;

(iii) The actual cost of providing the RPRS; and

(iv) A reference to the documentation to be provided in writing as indicated in paragraph (3)(h) below.

(b) The QSE shall provide documentation to allow ERCOT to verify the claimed amounts. All documentation submitted to ERCOT for verification pursuant to paragraph (3)(h) below shall be considered Protected Information in accordance with Section 1.3.1.1, Items Considered Protected Information.

(c) ERCOT shall not make payments for verifiable costs outside the defined documentation requirements until after the QSE has followed the steps outlined in paragraph (3)(i) below and the ERCOT Board has approved the documentation requirements.

(d) Natural gas costs, including transportation and storage costs directly related to this RPRS event for use in calculating the costs in paragraphs (3)(h)(i), (iv) and (vii) below, will require supporting documentation of sufficient detail to allow for the verification of the cost of natural gas consumed by the Resource receiving the RPRS Instruction. For gas fired Resources, such documentation will not be required if the requested incremental fuel cost is less than one hundred ten percent (110%) of the Fuel Index Price (FIP).

(e) Fuel oil costs submitted for verification shall be based on replacement costs directly related to this RPRS event for use in calculating the costs in paragraphs (3)(h)(i), (iv) and (vii) below. Documentation of fuel oil costs shall be in sufficient detail to allow for the verification of the replacement cost of fuel oil consumed by the Resource receiving the RPRS Instruction. Documentation may include contracts, invoices or other documents. For oil fired Resources, such documentation will not be required if the requested incremental fuel cost is less than one hundred ten percent (110%) of the Fuel Oil Price (FOP).

(f) For any Resource claiming Nitrogen Oxide (NOx) emissions allowances as part of the Startup Emission-related Cost or Operational Emission-related Cost, the Resource Entity may provide documentation supporting actual cost of emissions allowances used to comply with the RPRS Instruction. Such documentation will not be required if the requested emissions allowance cost is less than one hundred ten percent (110%) of the applicable NOx Emissions Allowance Index Price (NOxEAIP).

(g) The Resource Entity shall provide to ERCOT an attestation signed by an officer of the Resource Entity, in a form acceptable to ERCOT, specifying the type of fuel oil used.

(h) Defined Documentation Requirements

(i) Startup Fuel Cost, which is the fuel cost for bringing the unit On-line starting at first fire and up to its LSL and ready to go to full Load or the beginning of the RPRS period, whichever occurs first, to provide the RPRS shall be determined by multiplying the fuel consumption (MMBtu) to start up the Resource by the associated fuel cost ($/MMBtu).

(ii) Startup Emission-related Cost, which is the emission-related cost for bringing the unit On-line starting at first fire and up to its LSL and ready to go to full Load or the beginning of the RPRS period, whichever occurs first, to provide the RPRS shall be determined by multiplying the amount of emissions produced to start up the Resource by the associated emission cost ($/ton).

(A) For NOx emissions, the equation for this calculation is:

$$NOXC_S = Q * EAC_{NOX}$$

Where,

$NOXC_s$ = NOx emissions cost for the Resource ($)

s = Startup

Q = quantity of NOx emitted for start-up (first fire to LSL) from the Resource's Continuous Emission Monitoring (CEM) system (tons)

EAC_{NOX} ($/ton)= Actual NOx emissions allowance cost or NOx Emissions Index Price (NOxEAIP) whichever is applicable

(iii) Startup Non-Fuel Cost, which shall be based on either (A) or (B) below:

(A) Documented historical non-fuel startup costs expressed on a per unit start basis for the deployed Resource. If the historical non-fuel startup costs are more than one hundred percent (100%) of the Resource Category Non-Fuel Startup Costs (RCNFSC), the QSE shall provide documentation for such costs. Non-fuel start-up costs are limited to the costs associated with water, chemicals, labor and start-up power used in the start-up of the Resource. Supporting documentation shall include an itemized list in sufficient detail to allow for the verification of each cost incurred due to the RPRS.

(B) Generic RCNFSC as defined below. If the QSE chooses to use RCNFSC, all subsequent requests for non-fuel startup cost-based recovery requested by the QSE for the remainder of the calendar year for the specific deployed Resource shall be based on the RCNFSC.

Resource Category Non-Fuel Startup Costs (RCNFSC)

For the purpose of documentation, the RCNFSC represents the startup cost (excluding fuel) of capacity used for RPRS. The RCNFSC for each type of Resource shall be:

Combined Cycle greater than 90 MW** = $6,810
Combined Cycle less than or equal to 90 MW** = $5,310
Gas-Steam Supercritical Boiler = $4,800
Gas-Steam Reheat Boiler = $3,000
Gas-Steam Non-reheat or boiler without air-preheater = $2,310
Simple Cycle greater than 90 MW = $5,000
Simple Cycle less than or equal to 90 MW = $2,300
Renewable = $0

** Determined by capacity of largest simple-cycle combustion turbine in the train

(iv) Operational Fuel Cost, which shall be determined by multiplying the fuel consumption (MMBtu) at the LSL of the Resource by its associated fuel cost ($/MMBtu) for the intervals covered by the RPRS Instruction. Fuel consumption at the LSL shall be based upon a heat rate curve for the Resource from the most recently conducted heat rate tests filed with ERCOT. Test data shall be provided in sufficient detail to allow ERCOT to validate the heat rate curve provided.

(v) Operational Emission-related Cost, which shall be determined by multiplying the amount of emissions produced by the Resource at its LSL by the associated emission allowance cost ($/ton) for the intervals covered by the RPRS instruction. The amount of emissions produced at the LSL shall be based upon a certified emission rate curve for the Resource. The form of the certified emission rate curve shall be:

$CEC_R = A + (B*x) + (C*x^2) + (D*x^3) + (E*x^4)$

Where,

CEC = Certified Emission Rate Curve (lbs/MMBtu/hour)

A, B, C, D and E are coefficients specific to the Resource

R = Resource

x = MW

The emission rate curve shall be certified by an officer of the Resource owner as being accurate and representative of the Resource emissions and filed with ERCOT and may be different for each different emission product.

(A) For NOx emissions, the equation for Operational Emission-related Cost for RPRS is:

$OEC_{RPRS} = (CEC_{LSL}/2000) * F_{LSL} * EAC_{NOX} * N_{LSL}$

Where,

$CEC_{LSL} = A + (B*LSL) +(C*LSL^2) + (D*LSL^3) + (E*LSL^4)$

A, B, C, D and E are coefficients specific to the Resource

OEC_{RPRS} = Operational Emission-related Cost for RPRS

LSL = MW at LSL

F_{LSL} = Fuel burn in MMBtu/hour at LSL (from Resource I/O curve)

EAC_{NOX} = Actual NOx emissions allowance cost or NOx Emissions Index Price (NOxEAIP) ($/ton) whichever is applicable

N_{LSL} = number of intervals the Resource is at LSL for the RPRS instruction

(vi) Variable non-fuel maintenance costs (in dollars per MWh) for a specific deployed Resource, which shall be calculated based on: actual itemized variable maintenance costs contained in contracts with a third party or the manufacturer's recommended maintenance schedule and associated costs. Supporting documentation will be the corresponding excerpt of the appropriate contract from the third party or the maintenance schedule.

(vii) Fuel cost for bringing the unit Off-line from LSL as soon as possible (not to exceed three (3) hours) after the end of the RPRS period, in a manner consistent with Good Utility Practices, shall be determined by multiplying the fuel consumption (MMBtu) to bring the Resource Off-line by the associated fuel cost ($/MMBtu) minus the MCPE multiplied by the actual generation for shut down. Fuel quantity will be based on the Real Time metering of the fuel consumption for the Resource.

(viii) Unavoidable costs directly resulting from a delay in an accepted Outage for a Generating Resource due to an RPRS Instruction. Supporting documentation shall include an itemized list in sufficient detail to allow for the verification of each cost incurred due to the Outage delay. Further documentation supporting each line item must be provided upon ERCOT's request and may include copies of contracts, vendor invoices or other documents.

(ix) ERCOT nodal implementation surcharge (in dollars per MWh) for a specific Resource, as calculated in Section 9.7.6, for every interval in which the Resource operates at its LSL.

(i) Compensation for types of cost, whose documentation requirements are not covered in paragraphs (3)(h)(i) through (3)(h)(ix) above for the deployed Resource, will be denied pending possible review by the ERCOT Board. The requesting QSE may request approval of the documentation requirements by the ERCOT Board, and if requested will be considered by the ERCOT Board at its next regularly scheduled meeting for which proper notice may be posted following ERCOT's receipt of the request. The requesting QSE may request that this review be conducted at an Executive Session of the ERCOT Board. Requests must be presented in person by a representative of the company submitting the request and must also include language suitable to be included in the Protocols to define the documentation requirements for future requests of a similar nature. Subsequent to the approval of such costs, the requesting company shall submit a Protocol Revision Request (PRR), in accordance with Section 21, Process for Protocol Revision, incorporating the necessary documentation standards provided to the ERCOT Board. Once approved by the ERCOT Board, ERCOT will process the request for payments as described in Section 9.2.5, Resettlement Statement.

(j) Submit a signature sheet signed by the Authorized Representative of the Resource Entity certifying the costs submitted are directly attributable to the RPRS deployment and which satisfies the documentation standards in paragraph (3)(h) above.

(4) The calculation for RPRS to resolve Local Congestion is as follows:

$$\mathbf{LPC_{RPiuq} = -1 * MAX(0, LPS_{RPiu} + LPO_{RPiu})}$$

$$\mathbf{LPC_{RPiq} = SUM\ (LPC_{RPiuq})_u}$$

$$\mathbf{LPO_{RPiu} = SUM[(RCGMEC_c - MCPE_{jz}) * MIN(MINCAP_{iu}/4, MR_{ju})]_j}$$

If the unit is deemed to be Off-line as described in paragraph (1) above

Then:

$$\mathbf{LPS_{RPiu} = RCGSC_c/N}$$

If the unit is deemed to be On-line as described in paragraph (2) above

Then:

$$\mathbf{LPS_{RPiu} = 0}$$

The equation below will be used to determine the Total Replacement Reserve Payment to be allocated to each QSE as described in Section 6.9.2, QSE Obligations for Capacity Services Obtained in the Adjustment Period.

$$LPC_{RPi} = SUM\ (LPC_{RPiq})_q$$

Where:

c	Resource Category
i	Hourly interval being calculated
j	Settlement Intervals within the hourly interval i
u	Resource
q	QSE
z	Zone
N	Number of hours that this Resource is continuously procured
LPC_{RPiuq}	Replacement Reserve Service payment ($) per interval for the Resource
LPC_{RPiq}	Replacement Reserve Service payments ($) per interval for that QSE
LPC_{RPi}	Summations of Replacement Reserve Service payments ($) to resolve Local Congestion per interval for all QSEs
LPS_{RPiu}	Price for starting a unit that is selected for Replacement Reserve Service to resolve Local Congestion
LPO_{RPiu}	Price for operating a unit that is selected for Replacement Reserve Service to resolve Local Congestion

$MINCAP_{iu}$	Generating Unit LSL as reported in the unit's Resource Plan
MR_{ju}	Actual metered output of the Resource
$RCGMEC_c$	Resource Category Generic Minimum Energy Cost for a specific category of generation unit
$RCGSC_c$	Resource Category Generic Startup Cost for a specific category of generation unit

6.8.1.12 Payments for Balancing Energy Provided from Ancillary Services During the Operating Period

(1) All Balancing Energy deployed by a Dispatch Instruction and delivered by a generating Resource from Balancing Energy Service, RRS, RGS, or BES-Capable Non-Spinning Reserve Service (BESCNSRS) shall be settled as Balancing Energy at the MCPE of the Congestion Zone of the Resource providing the energy according to Section 6.8.1.13, Resource Imbalance, except when 30-Minute Non-Spinning Reserve Service (30MNSRS) is deployed in accordance with Section 6.7.4, Deployment of Non-Spinning Reserve Service. In that case, the MCPE for all Zones shall be the higher of (a) the posted MCPE or (b) FIP*15 MMBtu/MWh + $120 when there is no Congestion. When Congestion exists, the MCPE shall be the posted MCPE unless 30MNSRS is deployed in a zone, then the MCPE for that zone shall be the higher of (a) the posted MCPE or (b) FIP*15 MMBtu/MWh + $120.

(2) Deployed Balancing Energy Up on qualified Balancing Up Loads will be paid a capacity payment for the first Settlement Interval that it is deployed equal to the MCPC of NSRS for the hour in which the deployment occurs. A continuous deployment of Balancing Energy Up on qualified Loads for over sixty (60) minutes will be paid a capacity payment for each subsequent Settlement Interval which it is deployed equal to the MCPC of NSRS for that hour divided by four (4).

6.8.1.13 Resource Imbalance

Resource Imbalance ($) for each QSE for each interval for each zone will equal the Resource schedule (MWh) for Resources represented by that QSE minus the actual meter read (MWh) for the Resource multiplied by the Market Clearing Price for Energy ($/MWh). Resource Imbalance does not exclude DC Ties.

All generating Resource Balancing Energy deployed by a Dispatch Instruction from Balancing Energy Service, Responsive Reserve Service, Regulation Reserve Service, or Non-Spinning Reserve Service shall be paid as follows:

$$\mathbf{RI_{iq} = SUM\,(RI_{izq})_z}$$

Given:

$$RI_{izq} = NTE_{izq} * MCPE_{iz}$$

$$NTE_{izq} = (QRS_{izq} - MR_{izq})$$

The equation below represents the total Resource Imbalance Charges in a Congestion Zone for each interval.

$$\mathbf{RI_{iz} = SUM\ (RI_{izq})_q}$$

Where:

i:	interval being calculated
z:	zone being settled
q	QSE
RI_{izq}	Resource Imbalance ($) per interval per zone by QSE
RI_{iq}	Resource Imbalance ($) per interval for that QSE
RI_{iz}	Summation of Resource Imbalance ($) payments per interval per zonal for all QSEs in the market
NTE_{izq}	Net Energy per interval per zone per QSE is the difference between Resources scheduled and metered value
MR_{izq}	Metered value (MWh) for the Resource per interval, per zone per QSE using actual and/or estimated values
QRS_{izq}	Resource schedule (MWh) per interval per zone per QSE.
$MCPE_{iz}$	Market Clearing Price of Energy ($/MWh) per interval per zone

6.8.1.14 Payments for Capacity for Balancing Energy Up Load Deployed

A QSE that is instructed to deploy Balancing Up Load (BUL) shall be paid a capacity payment for the 15-minute interval the instruction is issued and the three (3) subsequent intervals according to the following formulas. A QSE that is instructed to continue to deploy BUL after the first four (4) 15-minute intervals will be paid a capacity payment for each subsequent interval instruction it is given to deploy BUL. The BUL capacity payment is calculated as follows:

$$PC_{BULiq} = -1 * ((MBUL_{iq} * MCPC_{NSi})/ 4)$$

$$MBUL_{iq} = MAX(BUL_{iq-0}, BUL_{iq-1}, BUL_{iq-2}, BUL_{iq-3})$$

$$BULPM_{iq} = BULETR_{iq} - \sum_{all \ldots zone} (BMRD_{iq} + BMRS_{iq})$$

$$BULETR_{iq} = [((BRATD_{iq} * AIMLD_{iq}) + (BRATS_{iq} * AIMLS_{iq})) - ((\sum FSBUL_{izq})_z + (\sum DSBUL_{izq})_z)]$$

[PIP112, PRR311, & PRR448: Insert the following when BUL Small Customer Load Management is implemented:]

Given:

IF SMALL CUSTOMER LOAD MANAGEMENT THEN

BUL_{iq} = $AIMLLM_{iq} - BMRLM_{iq}$

ELSE:

BUL_{iq} = $MIN[MIN(MAX(0,(\sum DIBUL_{izq})_z), MAX(0,((BRATD_{iq} * AIMLD_{iq})-BMRD_{iq}))) + MAX(0,((BRATS_{iq} * AIMLS_{iq})-BMRS_{iq})), (\sum DQ_{iqz})_z]$

$DIBUL_{izq}$ = $MAX[0, (\sum(MR_{izq} - (DSL_{izq} + INS_{izq} + INS_{ewiq} + SRS_{izq}))_z)]$

$$AIMLD_{iq} = \frac{\sum_{n=1}^{x} BMRD_{qin} - \underset{n=1,\ldots,x}{MAX}\left(BMRD_{qi1},\cdots,BMRD_{qix}\right) - \underset{n=1,\ldots,x}{MIN}\left(BMRD_{qi1},\cdots,BMRD_{qix}\right)}{x-2}$$

$$AIMLS_{iq} = \frac{\sum_{n=1}^{x} BMRS_{qin} - \underset{n=1,\ldots,x}{MAX}\left(BMRS_{qi1},\cdots,BMRS_{qix}\right) - \underset{n=1,\ldots,x}{MIN}\left(BMRS_{qi1},\cdots,BMRS_{qix}\right)}{x-2}$$

$$AMLPD_{iqn} = \frac{\left(BMRD_{qi-8n}\right)}{8}$$

$$AMLPS_{iqn} = \frac{\left(BMRS_{qi-8n}\right)}{8}$$

$$AMLPBD_{iq} = \frac{\sum_{n=1}^{x} AMLPD_{iqn}}{x-2}$$

$$AMLPBS_{iq} = \frac{\sum_{n=1}^{x} AMLPS_{iqn}}{x-2}$$

$$BRATD_{iq} = \frac{AMLPD_{iq0}}{AMLPBD_{iq}}$$

$$BRATS_{iq} = \frac{AMLPS_{iq0}}{AMLPBS_{iq}}$$

Where:

i	Settlement Interval being calculated

q	QSE
x	count of proxy days
z	zone
$AIMLD_{iq}$	Representative average interval metered BUL during the last ten (10) proxy days (in the case of weekdays) or six (6) proxy days (if deployment is on a weekend or holiday) for BUL meters that represent dynamic Load. Proxy days cannot be days when BUL was deployed during any interval.

[PIP112, PRR311, & PRR448: Insert the following when BUL Small Customer Load Management is implemented:]

AIMLLMiq QSE aggregate baseline Load for small customers who participate in Load management program assuming the program is not in operation from the appropriate Load Profile.

$AIMLS_{iq}$	Representative average interval metered BUL during the last ten (10) proxy days (in the case of weekdays) or six (6) proxy days (if deployment is on a weekend or holiday) for BUL meters that represent static Load. Proxy days cannot be days when BUL was deployed during any interval.
$AMLPBD_{iq}$	Average interval metered BUL from the prior ten (10) proxy days (in the case of weekday deployment) or six (6) proxy days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction for BUL meters that represent dynamic Load. Proxy days cannot be days when BUL was deployed during any interval.
$AMLPBS_{iq}$	Average interval metered BUL from the prior ten (10) proxy days (in the case of weekday deployment) or six (6) proxy days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction for BUL meters that represent static Load. Proxy days cannot be days when BUL was deployed during any interval.
$AMLPD_{iqn}$	Average interval metered BUL during the two (2) hours prior to the hour of BUL Notice in the n^{th} prior day for BUL meters that represent dynamic Load. Note, that n=0 refers to day of notice.
$AMLPS_{iqn}$	Average interval metered BUL during the two (2) hours prior to the hour of BUL Notice in the n^{th} prior day for BUL meters that represent static Load. Note, that n=0 refers to day of notice.
$BMRD_{iq}$	Aggregate of all actual qualified BUL meter readings per QSE per Settlement Interval per zone for BUL meters that represent dynamic Load.
$BMRD_{qimn}$	Aggregate of all qualified dynamic BUL meter readings per QSE q during the m^{th} 15-minute time interval after the Settlement Interval i on the n^{th} day prior to the day of settlement, where the n prior days shall be only weekdays excluding ERCOT-defined holidays if the day of settlement is a weekday, and shall be only weekends and ERCOT-defined holidays if the day of settlement is a weekend. Days in which BUL instructions occurred are excluded.

[PIP112, PRR311, & PRR448: Insert the following when BUL Small Customer Load Management is implemented:]

BMRLMiq QSE aggregate participating Customer Load during operation of Load management program from the appropriate Load Profile.

$BMRS_{iq}$	Aggregate of all actual qualified BUL meter readings per QSE per Settlement Interval per zone for BUL meters that represent static Load.
$BMRS_{qimn}$	Aggregate of all qualified static BUL meter readings per QSE *q* during the m^{th} 15-minute time interval after the Settlement Interval *i* on the n^{th} day prior to the day of settlement, where the *n* prior days shall be only weekdays excluding ERCOT-defined holidays if the day of settlement is a weekday, and shall be only weekends and ERCOT-defined holidays if the day of settlement is a weekend. Days in which BUL instructions occurred are excluded.
$BRATD_{iq}$	Ratio of average metered dynamic Load for 2 hours prior to BUL instruction to the average interval metered BUL from the prior ten (10) days (in the case of weekday deployment) or six (6) days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction.
$BRATS_{iq}$	Ratio of average metered static load for two (2) hours prior to BUL instruction to the average interval metered BUL from the prior ten (10) days (in the case of weekday deployment) or six (6) days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction.
BUL_{iq}	Quantity in MWhs of BUL deployed per Settlement Interval per QSE.
$BULETR_{iq}$	Total BUL expected reduction by QSE per interval ERCOT-wide.
$BULPM_{iq}$	Calculated to determine whether a QSE performed the BUL deployment and should receive a capacity payment.
$DIBUL_{izq}$	For QSEs with Dynamically Scheduled Loads, the average power delivered to ERCOT per interval per zone as a result of deploying BUL.
DQ_{iqz}	Deployed BUL quantity in MW per zone.
$DSBUL_{izq}$	For QSEs with Dynamically Scheduled Loads, the integrated signal for the interval that is an estimate in Real Time representing the real power interrupted in response to the deployment of BUL. $DSBUL_{izq}$ = zero (0) if Load is not dynamically scheduled.
DSL_{izq}	The integral of the Dynamically Scheduled Load telemetered to ERCOT for that QSE per interval per zone.
$FSBUL_{izq}$	Integrated signal for the interval sent by static scheduling QSEs to ERCOT and is an estimate in Real Time representing the real power interrupted in response to the deployment of BUL.
INS_{ewiq}	ERCOT-wide instructions for that QSE per interval.
INS_{izq}	Zonal Balancing Energy instructions given to that QSE per zone per interval.
$MBUL_{iq}$	Maximum quantity in MWhs of BUL deployed per Settlement Interval per QSE.

$MCPC_{NSi}$	Highest Non-Spinning Reserve Service Market Clearing Price of Capacity costs ($/MW) for the hour of all procurement processes.
MR_{izq}	Metered Resource value for that QSE per interval per zone.
$PCBUL_{iq}$	Capacity payment for instructed deployment of BUL per Settlement Interval per QSE.
SRS_{izq}	Static Resource schedule per interval per zone of that QSE.

6.8.1.15 Payments for Balancing Energy Provided from Uninstructed Deviation

Resources will be paid the full for up to the amount of all ERCOT instructed schedule deviations on an ERCOT-wide basis.

Resources will be paid a fraction of the market-clearing price for Uninstructed Deviations on an ERCOT-wide basis. An Uninstructed Deviation has occurred whenever the total metered Resources of a QSE for a Settlement Interval are different from the total of the scheduled Resources plus any Resource deployments instructed by ERCOT. An Uninstructed Deviation for a QSE will be equal to the energy that results during a Settlement Interval from the integrated schedule plus Dispatch Instructions minus the sum of the net metered value for the Generation Resources plus Load Resource response to Dispatch Instructions as described in Section 6.10.4, Ancillary Service Deployment Performance Measures.

6.8.1.15.1 Uninstructed Resource Charge Process

Once ERCOT has determined the Congestion Zones in which the Uninstructed Deviations of the QSE have occurred, an uninstructed pricing differential will be applied to a QSE representing Resources whenever one of the following two (2) conditions exists:

(1) The QSE representing Resources has total metered Resources for any Settlement Interval that are greater than the larger of one hundred one and one-half percent (101.5%) of the QSE’s total of schedules plus instructions or five (5) MWh over the total of schedules plus instructions when the integrated amount of ERCOT-wide regulation is less than negative twenty-five (– 25) MWhs in the interval. Upon one-day Notice, ERCOT can reduce the percentage and MWh tolerance to one hundred one percent (101%) and three (3) MWh, respectively, if significant price chasing exists.

(2) The QSE representing Resources has total metered Resources for any Settlement Interval that are less than the lesser of ninety-eight and one-half percent (98.5%) of the total schedule plus instructions or five (5) MWh under the total of schedules plus instructions when the integrated amount of ERCOT-wide regulation is greater than positive twenty-five (+ 25) MWh in the interval. Upon one day Notice, ERCOT can increase the percentage and MWh tolerance to ninety-nine percent (99%) and three (3) MWh, respectively, if significant price chasing exists.

(3) A QSE that schedules Uncontrollable Renewable Resources will not be subject to Uninstructed Deviation. The terms of this Section 6.8.1.15.1(3) shall immediately apply to QSEs that represent only Uncontrollable Renewable Resources. A QSE subject to the

terms of this paragraph shall observe the requirements of Section 4.4.15, QSE Resource Plans, and use best efforts to continuously update its Resouce Plan to reflect anticipated operating conditions.

If any condition listed in items (1) or (2), above, exists, then an Uninstructed Deviation pricing differential will be applied as follows:

(a) QSEs would be paid (or pay) for Instructed and Uninstructed Deviations at the zonal MCPE under Resource Imbalance Charge.

(b) An Uninstructed Deviation Charge Back would be calculated at a factor of the MCPE. The Uninstructed Deviation Charge Back would be applied to each Congestion Zone that a QSE has a deviation from schedule.

When the two conditions described in items (1) and (2), above, are met, an Uninstructed Factor will be instituted to reduce the payment to the QSE. The Uninstructed Factor will be adjusted in relation to the amount of Regulation Reserve Service that was required during that interval on a sliding scale.

Once a regulation is determined to be over or under the defined bandwidth, a QSE would be subject to the uninstructed charge for over-generation when the MCPE is positive, and for under-generation when the MCPE price is negative.

6.8.1.15.2 Determining the Uninstructed Factor

The Uninstructed Factor is a factor used to reduce the total payments made to a Resource for Uninstructed Deviations. The Uninstructed Factor could change by interval, depending on the following three conditions:

(1) The ERCOT approved MWh range of tolerance for regulation deployment in a Settlement Interval;

(2) The system wide integral amount above the tolerance level for Regulation Reserve Services (variable by interval);

(3) The upper limit of the amount (MWh) in which the Regulation Reserve Services can be deployed before the factor maximizes. The upper limit will be set at 125 MWh.

From a programmatic perspective, the Uninstructed Factor would be determined in the following manner:

WITHIN TOLERANCE: when regulation is deployed within the pre-defined tolerance level, the Resource receives one hundred percent (100%) of its Balancing Energy payment;

IF E_{regup} < tolerance AND $E_{regdown}$ < tolerance THEN

$$UF_i = 0$$

CASE OVERGENERATION: when regulation down is deployed beyond the pre-defined tolerance level, a QSE will be charged back for generation over their aggregated schedules and instructions;

ELSE IF $E_{regdown}$ > tolerance THEN

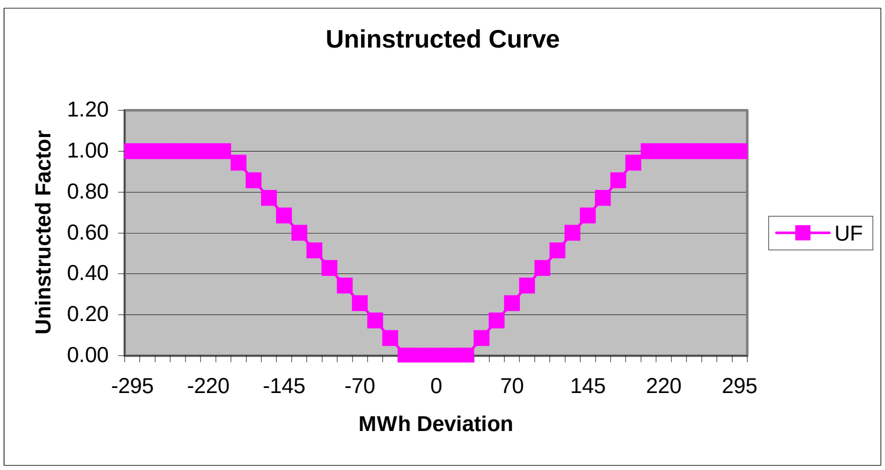
$$UF_i = \min(1.0, \left(\frac{E_{regdown,i} - tolerance}{UpperLimit - tolerance}\right)$$

CASE UNDERGENERATION: when regulation up is deployed beyond the tolerance level and any MCPEz is negative a QSE will be charged back for generation under their aggregated schedules and instructions as above.

ELSE E_{regup} > tolerance

$$UF_i = \min(1.0, \left(\frac{E_{regup,i} - tolerance}{UpperLimit - tolerance}\right)$$

Graphically, if the tolerance were +/- 25 MWhs of regulation, the Uninstructed Factor would look like this:



6.8.1.15.3 Uninstructed Charge Methodology and Equation

Once the Uninstructed Factor is determined on a system-wide basis for the Settlement Interval, it is possible to determine the 'price' to apply to QSE uninstructions. The Uninstructed Resource Charge would be determined by QSE for each zone in which the QSE had actual metered Resources.

The first step is to determine the QSE's Total Uninstructed Deviation. Each QSE's Total Uninstructed Deviation is calculated by adding the QSE Resource Schedule and all zonal and ERCOT wide instructions, and subtracting that amount from the Metered Resource Value. A dead band will be set according to each QSE's schedule plus instructions. If the QSE's Metered Resource Value is within this dead band percentage of +/- 1.5% but not less than +/- five (5) MWh of the schedule plus instructions for a Settlement Interval, then the QSE will not be subject to the Uninstructed Resource Charge.

[PIP112: Although the formula did not change, the "BUL" language incorporates Load Resources into one of the variables (MR). The current design does not have that capability. Once reworked, the following words in this comment box could be added to the Protocols.]

The QSE's Metered Resource Value will include both Generation and Load Resources. The amount of energy provided by a Load Resource will be obtained from the information submitted on the Resource Plan and the Settlement Meter of the Load Resource. Energy from a Load Resource is calculated for each Load Resource that is indicated available on the Resource Plan according to the following formula:

Energy from Load Resource = MAX (0, MIN ((the integral of the upper operating limit – Load Settlement Meter), (integral of the upper operating limit - integral of the lower operating limit)))

At the request of the QSE as specified by Section 6.10.6, Ancillary Service Deployment Performance Conditions, ERCOT will disregard energy from a Load Resource for the four consecutive Settlement Intervals following the time of the request by the QSE as it relates to the following formula.

$$TUD_{iq} = \sum_{All\ \text{zone}} \left(MR_{izq} - \left(SRURC_{izq} + INS_{izq} + \text{DSBUL}_{\text{izq}} \right) \right) - \sum INS_{ewiq}$$

Where:

TUD_{iq}	Total ERCOT-wide Uninstructed Deviation for that QSE per Settlement Interval
MR_{izq}	Metered Resource Value for that QSE per Settlement Interval per zone
$SRURC_{izq}$	The Resource Schedule (with out any DC Tie import schedules) smoothed for a 10-minute ramp per Settlement Interval per zone of that QSE, plus the Dynamic Schedule per Settlement Interval per zone of that QSE, plus the DC Tie import schedules per Settlement Interval per zone of that QSE.

[PRR601, PRR803: Replace the definition above with the following upon system implementation:]

$SRURC_{izq}$	The Resource Schedule (with out any DC Tie import schedules) smoothed for a fourteen (14)-minute ramp per Settlement Interval per zone of that QSE, plus the Dynamic Schedule per Settlement Interval per zone of that

	QSE, plus the DC Tie import schedules per Settlement Interval per zone of that QSE.

INS_{izq}	Zonal Balancing Energy instructions given to that QSE per zone per Settlement Interval
INS_{ewiq}	ERCOT-wide Instructions for that QSE per Settlement Interval
$DSBUL_{izq}$	For QSEs with Dynamically Scheduled Loads, the integrated signal for the Settlement Interval that is an estimate in Real Time representing the real power interrupted in response to the deployment of BUL. $DSBUL_{izq}$ = zero (0) if Load is not dynamically scheduled.

If the QSE's Total Uninstructed Deviation is zero (0), then the zonal Uninstructed Deviation for every zone is zero (0).

$$ZUD_{izq} = 0$$

If the QSE's Total Uninstructed Deviation is positive, then the total Uninstructed Deviation will be allocated to those zones in which the value of adding the QSE's Resource Schedule in that zone and zonal instructions in that zone, and subtracting from the Metered Resource Value in that zone is positive.

$$ZUD_{izq} = \frac{\max(0, MR_{izq} - (SRURC_{izq} + INS_{izq} + DSBUL_{izq}))}{\sum_{all\ \text{zone}} \max(0, MR_{izq} - (SRURC_{izq} + INS_{izq} + DSBUL_{izq}))} * TUD_{iq}$$

If the QSE's Total Uninstructed Deviation is negative, then the total Uninstructed Deviation will be allocated to those zones in which the value of adding the QSE's Resource Schedule in that zone and zonal instructions in that zone, and subtracting from the Metered Resource Value in that zone is negative.

$$ZUD_{izq} = \frac{\min(0, MR_{izq} - (SRURC_{izq} + INS_{izq} + DSBUL_{izq}))}{\sum_{all\ \text{zone}} \min(0, MR_{izq} - (SRURC_{izq} + INS_{izq} + DSBUL_{izq}))} * TUD_{iq}$$

Where:

i	interval
q	QSE
z	Congestion Zone
INS_{izq}	Zonal Balancing Energy instructions given to that QSE per zone per interval.
MR_{izq}	Metered Resource Value for that QSE per interval per zone.

$SRURC_{izq}$	=	$SRSURC_{izq}$ + (SRA_{izq} or SRD_{izq}) + DC Tie import schedules_{izq}

$$SRSURC_{izq} = SRSNDCCURR_{izq} + ((SRSNDCPREV_{izq} - SRSNDCCURR_{izq}) / 12)+((SRSNDCNEXT_{izq} - SRSNDCCURR_{izq}) / 12)$$

[PRR601, PRR803: Replace the equation above with the following upon system implementation:]

$$SRSURC_{izq} = SRSNDCCURR_{izq} + ((SRSNDCPREV_{izq} - SRSNDCCURR_{izq}) / 8.57)+((SRSNDCNEXT_{izq} - SRSNDCCURR_{izq}) / 8.57)$$

Where:

INS_{izq}	Zonal Balancing Energy instructions given to that QSE per zone per interval.
MR_{izq}	Metered Resource Value for that QSE per interval per zone.

$$SRURC_{izq} = SRSURC_{izq} + (SRA_{izq} \text{ or } SRD_{izq}) + \text{DC Tie import schedules}_{izq}$$

$$SRSURC_{izq} = SRSNDCCURR_{izq} + ((SRSNDCPREV_{izq} - SRSNDCCURR_{izq}) / 12)+((SRSNDCNEXT_{izq} - SRSNDCCURR_{izq}) / 12)$$

[PRR601, PRR803: Replace the equation above with the following upon system implementation:]

$$SRSURC_{izq} = SRSNDCCURR_{izq} + ((SRSNDCPREV_{izq} - SRSNDCCURR_{izq}) / 8.57)+((SRSNDCNEXT_{izq} - SRSNDCCURR_{izq}) / 8.57)$$

Where:

DC Tie import schedules_{izq}	The DC Tie imports scheduled per interval per zone of that QSE.
(SRA_{izq} or SRD_{izq})	The scheduled Resource (actual or dynamic, which ever is selected based on the dynamic scheduling logic) per interval per zone of that QSE.
$SRSNDCCURR_{izq}$	The scheduled Resource static minus any DC Tie import schedules, for the current interval, per interval per zone per QSE.
$SRSNDCNEXT_{izq}$	The scheduled Resource static minus any DC Tie import schedules for the next interval, per interval per zone per QSE.
$SRSNDCPREV_{izq}$	The scheduled Resource static minus any DC Tie import schedules for the previous interval, per interval, per zone, and per QSE.

$SRSURC_{izq}$ The scheduled Resource static (without any DC Tie import schedules) smoothed for a ten (10) minute ramp, per interval per zone of that QSE.

[PRR601, PRR803: Replace the definition above with the following upon system implementation:]

$SRSURC_{izq}$ The scheduled Resource static (without any DC Tie import schedules) smoothed for a fourteen (14) minute ramp, per interval per zone of that QSE.

$SRURCRS_{izq}$ The Resource Schedule (without any DC Tie import schedules) smoothed for a ten (10) minute ramp per interval per zone of that QSE, plus the Dynamic Schedule per interval per zone of that QSE, plus the DC Tie import schedules per interval per zone of that QSE.

[PRR601, PRR803: Replace the definition above with the following upon system implementation:]

$SRURCRS_{izq}$ The Resource Schedule (without any DC Tie import schedules) smoothed for a fourteen (14) minute ramp per interval per zone of that QSE, plus the Dynamic Schedule per interval per zone of that QSE, plus the DC Tie import schedules per interval per zone of that QSE.

TUD_{iq} Total ERCOT wide Uninstructed Deviation for that QSE per interval.

ZUD_{izq} Zonal Uninstructed Deviation for that QSE per interval for that zone.

$DSBUL_{izq}$ For QSEs with Dynamically Scheduled Loads, the integrated signal for the interval that is an estimate in Real Time representing the real power interrupted in response to the deployment of BUL. $DSBUL_{izq}$ = zero (0) if Load is not dynamically scheduled.

The second step is to compare the market-clearing price of an interval to a benchmark in each zone and calculate the Uninstructed Resource Charge for each QSE in each zone. If the MCPE for the zone is negative, a QSE would be subject to the Uninstructed Resource Charge for under-generation. If the MCPE is positive, then a QSE is subject to the Uninstructed Resource Charge for over-generation.

The Uninstructed Resource Charge for that zone will be the product of the zonal uninstructed quantity, the MCPE for that Settlement Interval for that zone, and the previously determined Uninstructed Factor for that Settlement Interval.

This activity would be performed for every Congestion Zone for each QSE.

CASE: PRICE CHASING[1]

IF MCPEiz ≥ 0 and QSE outside deadband, then:

$$URC_{izq} = \left(Max\left[0, ZUD_{izq}\right]\right) * \left(MCPE_{iz} \times UF_i\right)$$

CASE: COST OPTIMIZING[2]

ELSE MCPEiz < 0 and QSE outside deadband Then:

$$URC_{izq} = \left(Min\left[0, ZUD_{izq}\right]\right) * \left(MCPE_{iz} \times UF_i\right)$$

Where:

URC_{iz}	Uninstructed Resource Charge for that QSE per zone per Settlement Interval
ZUD_{izq}	Zonal Uninstructed Deviation for that QSE per zone per Settlement Interval
$MCPE_{iz}$	Market Clearing Price for Energy in that zone of that Settlement Interval
UF_i	Uninstructed Factor determined in accordance to deployed regulation

6.8.2 Capacity and Energy Payments for Out-of-Merit or Zonal OOME Service

6.8.2.1 Resource Category Generic Costs

To properly calculate Local Congestion costs, it is necessary to establish certain generic costs associated with Resources that will be used to calculate production costs incurred when the Resource(s) provides Out of Merit or Zonal OOME Service. These generic Resource costs include generic fuel costs and generic startup costs.

(1) Each ERCOT Generation Resource will be assigned to one of the following Resource Categories for the purpose of determining generic fuel costs:

Nuclear
Hydro

[1] In this case, only QSE's that overgenerate would be subject to the uninstructed charge when the price is greater than the benchmarked costs.

Coal and Lignite
Combined Cycle greater than 90 MW**
Combined Cycle less than or equal to 90 MW**
Gas-Steam Supercritical Boiler
Gas-Steam Reheat Boiler
Gas-Steam Non-reheat or boiler without air-preheater
Simple Cycle greater than 90 MW
Simple Cycle less than or equal to 90 MW
Diesel (and all other diesel or gas-fired Resources)
Renewable (i.e., non-Hydro renewable Resources)
Block Load Transfer
DC Tie with non-ERCOT Control Area

** Determined by capacity of largest simple cycle combustion turbine in the train

The category of each Resource will be reported to ERCOT by the Generation Entity. Each Generation Entity shall ensure that each of its Resources is in the correct Resource category.

(2) The Fuel Index Price (FIP) shall be the Midpoint price, expressed in $/MMBtu, published in Gas Daily, in the Daily Price Survey, under the heading "East-Houston-Katy, Houston Ship Channel" for the day of the OOMC or OOME deployment. The FIP for Saturdays, Sundays, holidays and other days for which there is no FIP published in Gas Daily, shall be the next published FIP after the day of the OOMC or OOME deployment. In the event that the FIP is not published for more than two (2) days, the previous day published FIP will be used for Initial Settlement and the next day published FIP will be used for the Final Settlement Statement.

(3) Resource Category Generic Fuel Costs

Each ERCOT Generation Resource will be assigned a Resource Category Generic Fuel Cost (RCGFC) based on the Resource Category to which it is assigned. For Nuclear, Hydro, Coal and Lignite Resources, the RCGFC will be a fixed dollar/MWh amount as shown below. For the remaining Resource categories (except Renewable), the RCGFC will be the product of a heat rate (based on the heat rates used for the Capacity Auction) and a Fuel Index Price (FIP). The RCGFC for Renewable Resources will be $0/MWh.

The RCGFC for each type of Resource for upward instructions will be:

Nuclear = $15.00/MWh
Hydro = $10.00/MWh
Coal and Lignite = $18.00/MWh
Combined Cycle greater than 90 MW** = FIP * 9 MMBtu/MWh
Combined Cycle less than or equal to 90 MW** = FIP * 10 MMBtu/MWh
Gas-Steam Supercritical Boiler = FIP * 10.5 MMBtu/MWh
Gas-Steam Reheat Boiler = FIP * 11.5 MMBtu/MWh
Gas-Steam Non-reheat or boiler without air-preheater = FIP * 14.5 MMBtu/MWh
Simple Cycle greater than 90 MW = FIP * 14 MMBtu/MWh

Simple Cycle less than or equal to 90 MW = FIP * 15 MMBtu/MWh
Diesel = FIP * 16 MMBtu/MWh
Block Load Transfer = FIP * 18 MMBtu/MWh
DC Tie with non-ERCOT Control Area = FIP * 18 MMBtu/MWh
Renewable = $0/MWh
LaaR = FIP * 18 MMBtu/MWh

** Determined by capacity of largest simple cycle combustion turbine in the train

The RCGFC for each type of Resource for downward instructions will be:

Nuclear = $0.00/MWh
Hydro = $0.00/MWh
Coal and Lignite = $3.00/MWh
Combined Cycle greater than 90 MW** = FIP * 5 MMBtu/MWh
Combined Cycle less than or equal to 90 MW** = FIP * 6.5 MMBtu/MWh
Gas-Steam Supercritical Boiler = FIP * 7.5 MMBtu/MWh
Gas-Steam Reheat Boiler = FIP * 9.5 MMBtu/MWh
Gas-Steam Non-reheat or boiler without air-preheater = FIP * 10.5 MMBtu/MWh
Simple Cycle greater than 90 MW = FIP * 10.5 MMBtu/MWh
Simple Cycle less than or equal to 90 MW = FIP * 12 MMBtu/MWh
Diesel = FIP * 12 MMBtu/MWh
Block Load Transfer = Not Applicable
DC Tie with non-ERCOT Control Area = Not Applicable
Renewable = $0/MWh

** Determined by capacity of largest simple cycle combustion turbine in the train

(4) Resource Category Generic Startup Costs

Resource Category Generic Startup Costs (RCGSC) represents the startup cost of capacity used for Replacement Reserve Service. The RCGSC for each type of Resource will be:

Nuclear = $0.00/MWh
Hydro = $0.00/MWh
Coal and Lignite = $0.00/MWh
Combined Cycle – when there are five hours or more between shutdown and startup for an OOMC instruction:
Combined Cycle greater than 90 MW** = $6,810 + (FIP * 2,200 MMBtu)
Combined Cycle less than or equal to 90 MW** = $5,310 + (FIP * 1,200 MMBtu)
Combined Cycle – when there are less than five (5) hours between shutdown and startup for an OOMC instruction:
Combined Cycle greater than 90 MW** = $6,810 + (FIP * 1,100 MMBtu)

Combined Cycle less than or equal to 90 MW** = $5,310 + (FIP * 600 MMBtu)
Gas-Steam Supercritical Boiler = $4,800 + (FIP * 16.5 MMBtu/MW * RMCu)
Gas-Steam Reheat Boiler = $3,000 + (FIP * 9.0 MMBtu/MW * RMCu)
Gas-Steam Non-reheat or boiler without air-preheater = $2,310 + (FIP * 2.30 MMBtu/MW * RMCu)
Simple Cycle greater than 90 MW = $5,000 + (FIP * 1.1 MMBtu/MW * RMCu)
Simple Cycle less than or equal to 90 MW = $2,300 + (FIP * 1.1 MMBtu/MW * RMCu)
Renewable = $0

Where:

RMC	Resource Maximum Capacity (in MW)
u	unit

** Determined by capacity of largest Simple Cycle combustion turbine in the train

(5) Resource Category Generic Minimum Energy Cost

Resource Category Generic Minimum Energy Cost (RCGMEC) is the heat rate of a unit, in one of these categories, at its Low Sustainable Limit as set forth in the Resource Plan for that unit (as required by Section 4.4.15, QSE Resource Plans) when the Resource is selected to provide Out-of-Merit Service multiplied by the Fuel Index Price as defined in Section 6.8.2.1, Resource Category Generic Costs, item (2). The RCGMEC for each type of Resource will be:

Nuclear Units = zonal MCPE for the units location
Hydro Units = zonal MCPE for the units location
Coal & Lignite Units = zonal MCPE for the units location
Combined Cycle greater than 90 MW** = 10 MMBtu/MWh * FIP
Combined Cycle less than or equal to 90 MW** = 10 MMBtu/MWh * FIP
Gas-Steam Supercritical Boiler = 16.5 MMBtu/MWh * FIP
Gas-Steam Reheat Boiler = 17.0 MMBtu/MWh * FIP
Gas-Steam Non-reheat or boiler without air-preheater = 19.0 MMBtu/MWh * FIP
Simple Cycle greater than 90 MW = 15.0 MMBtu/MWh * FIP
Simple Cycle less than or equal to 90 MW = 15.0 MMBtu/MWh * FIP

** Determined by capacity of largest simple cycle combustion turbine in the train

6.8.2.2 Capacity and Minimum Energy Payments

(1) OOMC Service may be used by ERCOT as a procured Replacement Reserve Resource in the Adjustment Period where necessary to support emergency operations and provide voltage support, stability, or to manage localized transmission limitations. All Generation Resources that are available and plan to be Off-line during the Settlement Interval for which Ancillary Services are being procured are eligible to be selected to provide OOMC Service. ERCOT shall not issue an OOME Up Dispatch Instruction for

the energy associated with the LSL as set forth in the Resource Plan (as required by Section 4.4.15, QSE Resource Plans) for which it has issued an OOMC Dispatch Instruction. Zonal OOME Service will only be provided from Resources that are already On-line at the time of the Zonal OOME Dispatch Instruction and will not receive a capacity payment.

(2) The QSE for a Generation Resource that provides OOMC Service and produces less than 0.25 MWh of net metered generation for more than three (3) consecutive 15-minute Settlement Intervals within twenty-seven (27) 15-minute Settlement Intervals preceding the OOMC Dispatch Instruction is eligible for startup costs and Minimum Energy costs, and may be charged a clawback against startup costs unless the Generation Resource is a Quick Start Unit as defined in Section 2, Definitions and Acronyms. If the Generation Resource is a Quick Start Unit and it is Off-line at any time during at least one (1) 15-minute Settlement Interval within the four (4) 15-minute Settlement Intervals preceding the OOMC Dispatch Instruction, then it is eligible for startup costs and minimum energy costs and may be charged a clawback against startup costs.

(a) Startup costs are calculated as the RCGSC for starting the Generation Resource.

(b) Minimum Energy costs are calculated as the RCGMEC less the MCPE for operating at the LSL as set forth in the Resource Plan for that Generation Resource during the instructed Settlement Interval(s).

(c) If the Generation Resource produces energy prior to the time period specified by the OOMC Dispatch Instruction, there shall be a clawback charge against the Resource Category Generic Startup Cost. This charge shall be calculated for:

(i) The twelve (12) 15-minute Settlement Intervals prior to the OOMC Dispatch Instruction; or

(ii) If the Generation Resource produces less than 0.25 MWh of net metered generation in any of the twelve (12) 15-minute Settlement Intervals prior to the OOMC Dispatch Instruction, the Settlement Intervals beginning in the Settlement Interval following the last 15-minute Settlement Interval with less than 0.25 MWh of net metered generation and in all remaining Settlement Intervals prior to the start of the OOMC Dispatch Instruction.

(iii) If a Generation Resource is On-line in response to a Resource-specific Dispatch Instruction during any of the twelve (12) Settlement Intervals preceding the OOMC Dispatch Instruction, the Generation Resource will be exempt from the clawback charge in those Settlement Intervals, which the QSE for the Generation Resource may submit a valid dispute pursuant to Section 9.5, Settlement and Billing Dispute Process, to recover.

(iv) If the Generation Resource is a Quick Start Unit as defined in Section 2, and is Off-line in any of the twelve (12) 15-minute Settlement Intervals preceding the OOMC Dispatch Instruction, the Settlement Intervals beginning in the Settlement Interval following the last 15-minute

Settlement Interval during which the Quick Start Unit is Off-line at any time and in all remaining Settlement Intervals prior to the start of the OOMC Dispatch Instruction.

(3) Generation Resources that are not eligible as specified in paragraph (2) above when their QSE provides OOMC Service when instructed will be paid Minimum Energy costs. Minimum Energy costs are calculated as the RCGMEC less the MCPE for operating at the Low Sustainable Limit of the Resource during the instructed Settlement Interval(s).

(4) If the Generation Resource remains On-line beyond the time period specified by the OOMC Dispatch Instruction, there shall be a charge against the Resource Category Generic Startup Cost. This charge will only be applied if the MCPE is greater than the Resource Category Generic Fuel Cost for an upward instruction. If the difference is positive and the Resource Category Generic Startup Cost due is greater than zero (0), it will be subtracted from the payment for Resource Category Generic Startup Cost for starting the Generation Resource. This charge shall continue to be calculated for all Settlement Intervals, except for the first three (3) hours after the end of the OOMC Dispatch Instruction, until:

(a) The Generation Resource is Off-line;

(b) The end of the Operating Day; or

(c) The next Resource-specific deployment for the Generation Resource within the Operating Day, whichever comes first.

When the Resource-specific OOMC instruction is issued, the QSE may maintain a Balanced Schedule, such as scheduling the ramping and minimum energy or being selected by ERCOT to provide Balancing Energy Service. When a QSE receives an OOMC Dispatch Instruction less than thirty (30) minutes before the end of the Adjustment Period or during the Operating Period, the deviation resulting from ramping or minimum energy of a Resource selected to provide OOMC Service will not be subject to Uninstructed Resource Charge during the instructed interval(s), including the ramp interval(s) of such Resource.

(5) If ERCOT sends a QSE a Resource-specific Dispatch Instruction for OOMC Service ("OOMC Instruction") and the payment for OOMC Service does not cover all costs of providing the OOMC Service plus a ten percent (10%) premium, then that QSE may submit verifiable, additional costs directly attributable to the OOMC Dispatch Instruction, which exceed the payment for OOMC Service calculated pursuant to paragraph (6) below. The QSE will be paid only for additional costs directly attributable to the OOMC Service, plus the premium. Verifiable costs are subject to the approved documentation requirements in paragraph (5)(h) below. The premium to be provided shall be the product of the costs of providing the service times ten percent (10%). However, the premium will not apply to the nodal implementation surcharge defined in Section 9.7.6, ERCOT Nodal Implementation Surcharge. Verification of these costs must be submitted to ERCOT by the QSE or the Resource to allow resolution by the end

of the dispute process for Settlement True-Up as defined in Section 9.2.6, True-Up Statement.

(a) After receiving the Initial Statement for the subject Operating Day, a QSE shall submit a settlement dispute in accordance with the dispute process outlined in Section 9.5. In addition to the standard information required on the dispute form on the ERCOT Portal, the dispute should clearly indicate:

(i) The Dispatch Instruction received from ERCOT to provide the OOMC Services;

(ii) The payment received for providing the OOMC Service;

(iii) The actual cost of providing the OOMC Service; and

(iv) A reference to the documentation to be provided in writing as indicated in paragraph (5)(h) below.

(b) The QSE shall provide documentation to allow ERCOT to verify the claimed amounts. All documentation submitted to ERCOT for verification pursuant to paragraph (5)(h) below shall be considered Protected Information in accordance with Section 1.3.1.1, Items Considered Protected Information.

(c) ERCOT shall not make payments for verifiable costs outside the defined documentation requirements until after the QSE has followed the steps outlined in paragraph (5)(j) below and the ERCOT Board has approved the documentation requirements.

(d) Natural gas, including transportation and storage costs directly related to this OOMC event for use in calculating the costs in paragraphs (5)(h)(i), (iv) and (vii) below, will require supporting documentation of sufficient detail to allow for the verification of the cost of fuel consumed by the Resource receiving the OOMC Instruction. For gas fired Resources, such documentation will not be required if the requested incremental fuel cost is less than one hundred ten percent (110%) of the FIP.

(e) Fuel oil costs submitted for verification shall be based on replacement costs directly related to this OOMC event for use in calculating the costs in paragraphs (3)(h)(i), (iv) and (vii) of Section 6.8.1.11, Local Congestion Replacement Reserve Payment to QSE. Documentation of fuel oil costs shall be in sufficient detail to allow for the verification of the replacement cost of fuel oil consumed by the Resource receiving the OOMC Instruction. Documentation may include contracts, invoices or other documents. For oil fired Resources, such documentation will not be required if the requested incremental fuel cost is less than one hundred ten percent (110%) of the FOP.

(f) For any Resource claiming NOx emissions allowances as part of Startup Emission-related Cost or Operational Emission-related Cost, the Resource Entity may provide documentation supporting actual cost of emissions allowances used to comply with the OOMC instruction. Such documentation will not be required if the requested emissions allowance cost is less than one hundred ten percent (110%) of the applicable NOxEAIP.

(g) The Resource Entity shall provide to ERCOT an attestation signed by an officer of the Resource Entity, in a form acceptable to ERCOT, specifying the type of fuel oil used.

Defined Documentation Requirements

(i) Startup Fuel Cost which is the fuel cost for bringing the unit On-line starting at first fire and up to its LSL and ready to go to full Load or the beginning of the OOMC period, whichever occurs first, to provide the OOMC Service shall be determined by multiplying the fuel consumption (MMBtu) to start up the Resource by the associated fuel cost ($/MMBtu).

(ii) Startup Emission-related Cost, which is the emission-related cost for bringing the unit On-line starting at first fire and up to its LSL and ready to go to full Load or the beginning of the OOMC period, whichever occurs first, to provide the OOMC Service shall be determined by multiplying the amount of emissions produced to start up the Resource by the associated emission cost ($/ton).

(A) For NOx emissions, the equation for this calculation is:

$NOXC_S = Q * EAC_{NOX}$

Where,

$NOXC_s$ = NOx emissions cost for the Resource ($)

s = Startup

Q = quantity of NOx emitted for start-up (first fire to LSL) from the Resource's Continuous Emission Monitoring (CEM) system (tons)

EAC_{NOX} = Actual NOx emissions allowance cost or NOx Emissions Index Price (NOxEAIP) ($/ton) whichever is applicable

(iii) Startup Non-Fuel Cost, which shall be based on either (A) or (B) below:

(A) Documented historical non-fuel startup costs expressed on a per unit start basis for the deployed Resource. If the historical non-fuel startup costs are more than one hundred percent (100%) of the RCNFSC, the QSE shall provide documentation for such costs. Non-fuel start-up costs are limited to the costs associated with water, chemicals, labor and start-up power used in the start-up of the Resource. Supporting documentation shall include an itemized list in sufficient detail to allow for the verification of each cost incurred due to the OOMC Service.

(B) Generic RCNFSC as defined below. If the QSE chooses to use RCNFSC, all subsequent requests for non-fuel startup cost-based recovery requested by the QSE for the remainder of the calendar year for the specific deployed Resource shall be based on the RCNFSC.

Resource Category Non-Fuel Startup Costs (RCNFSC)

For the purpose of documentation, the RCNFSC represents the startup cost (excluding fuel) of capacity used for RPRS. The RCNFSC for each type of Resource shall be:

Combined Cycle greater than 90 MW** = $6,810
Combined Cycle less than or equal to 90 MW** = $5,310
Gas-Steam Supercritical Boiler = $4,800
Gas-Steam Reheat Boiler = $3,000
Gas-Steam Non-reheat or boiler without air-preheater = $2,310
Simple Cycle greater than 90 MW = $5,000
Simple Cycle less than or equal to 90 MW = $2,300
Renewable = $0

** Determined by capacity of largest simple-cycle combustion turbine in the train

(iv) Operational Fuel Cost, which shall be determined by multiplying the fuel consumption (MMBtu) at the LSL of the Resource by its associated fuel cost ($/MMBtu) for the intervals covered by the OOMC Instruction. Fuel consumption at the LSL shall be based upon a heat rate curve for the Resource from the most recently conducted heat rate tests filed with ERCOT. Test data shall be provided in sufficient detail to allow ERCOT to validate the heat rate curve provided.

(v) Operational Emission-related Cost, which shall be determined by multiplying the amount of emissions produced by the Resource at its LSL by the associated emission allowance cost ($/ton) for the intervals covered by the OOMC instruction. The amount of emissions produced at the LSL shall be based upon a certified emission rate curve for the Resource. The form of the certified emission rate curve shall be:

$$CEC_R = A + (B*x) + (C*x^2)+ (D*x^3) + (E*x^4)$$

Where,

CEC = Certified Emission Rate Curve (lbs/MMBtu/hour)

A, B, C, D and E are coefficients specific to the Resource

R = Resource

x = MW

This emission rate curve shall be certified by an officer of the Resource owner as being accurate and representative of the Resource emissions and filed with ERCOT and may be different for each different emission product.

(A) For NOx emissions, the equation for Operational Emission-related Cost for OOMC is:

OEC_{OOMC} (\$) = $(CEC_{LSL}/2000) * F_{LSL} * EAC_{NOX} * N_{LSL}$

Where,

$CEC_{LSL} = A + (B*LSL) + (C*LSL^2) + (D*LSL^3) + (E*LSL^4)$

A, B, C, D and E are coefficients specific to the Resource

OEC_{OOMC} = Operational Emission-related Cost for OOMC

LSL = MW at LSL

F_{LSL} = Fuel burn in MMBtu/hour at LSL (from Resource I/O curve)

EAC_{NOX} = Actual NOx emissions allowance cost or NOx Emissions Index Price (NOxEAIP) (\$/ton) whichever is applicable

N_{LSL} = number of intervals the Resource is at LSL for the OOMC instruction

(vi) Variable non-fuel maintenance cost (in dollars per MWh) for a specific deployed Resource, which shall be calculated based on: actual itemized variable maintenance costs contained in contracts with a third party or the manufacturer's recommended maintenance schedule and associated costs. Supporting documentation will be the corresponding excerpt of the appropriate contract from the third party or the maintenance schedule.

(vii) Fuel cost for bringing the unit Off-line from LSL as soon as possible (not to exceed three (3) hours) after the end of the OOMC period, in a manner consistent with Good Utility Practices, shall be determined by multiplying the fuel consumption (MMBtu) to bring the Resource Off-line by the associated fuel cost (\$/MMBtu) minus the MCPE multiplied by the actual generation for shut down. Fuel quantity will be based on the Real-Time metering of the fuel consumption for the Resource.

(viii) Unavoidable costs directly resulting from a delay in an accepted Outage for a Generating Resource due to an OOMC instruction. Supporting documentation shall include an itemized list in sufficient detail to allow for the verification of each cost incurred due to the Outage delay. Further documentation supporting each line item must be provided upon ERCOT's request and may include copies of contracts, vendor invoices or other documents.

(ix) ERCOT nodal implementation surcharge (in dollars per MWh) for a specific Resource, as calculated in Section 9.7.6, or every interval in which the Resource operates at its LSL.

(i) Compensation for types of cost, whose documentation requirements are not covered in paragraphs (5)(h)(i) through (5)(h)(ix) above for the deployed Resource, will be denied pending possible review by the ERCOT Board. The requesting QSE may request approval of the documentation requirements by the ERCOT Board, and if requested will be considered by the ERCOT Board at its next regularly scheduled meeting for which proper notice may be posted following ERCOT's receipt of the request. The requesting party may request that this review be conducted at an Executive Session of the ERCOT Board. Requests must be presented in person by a representative of the company submitting the request and must also include language suitable to be included in the Protocols to define the documentation requirements for future requests of a similar nature. Subsequent to the approval of such costs, the requesting company shall submit a PRR, in accordance with Section 21, Process for Protocol Revision, incorporating the necessary documentation standards provided to the ERCOT Board. Once approved by the ERCOT Board, ERCOT will process the request for payments as described in Section 9.2.5, Resettlement Statement.

(j) Submit a signature sheet signed by the Authorized Representative of the Resource Entity certifying the costs submitted are directly attributable to the OOMC deployment and which satisfies the documentation standards in paragraph (5)(h) above.

(6) The calculation for capacity payments and minimum energy of Out of Merit Service is as follows:

$$\mathbf{PC_{OOMRPqi} = SUM\ (PC_{OOMRPqui})_u}$$

If BP_{RPqui} exists,

Then:

$$PC_{OOMRPqui} = -1 * MIN\ [(BP_{\mathbf{RPqui}} * C_{OOMRPui}),\ (PS_{ui} + PO_{ui})]$$

Else:

$PC_{OOMRPqui}$ = $-1 * (PS_{ui} + PO_{ui})$

If the unit is deemed to be On-line as described in paragraph (2) above,

Then:

PS_{ui} = 0

PO_{ui} = $SUM\ [(RCGMEC_c – MCPE_{jz}) * MIN\ (MINCAP_u/4, MR_{uj})]_j$

If the unit is deemed to be Off-line as described in paragraph (2) above,

Then:

PS_{ui} = $[Max\ (0, RCGSC_c – (SUM_s(MCPE_{wz} * MR_{uw})))]$ / (# of instructed hours)

PO_{ui} = $SUM\ [(RCGMEC_c – MCPE_{jz}) * MIN\ (MINCAP_u/4, MR_{uj})]_j$

If the unit is not a nuclear, hydro, coal or lignite unit and continues to remain On-line after the instructed intervals as described in paragraph (4) above,

Then:

CRCGSC = $SUM_a\ [(MCPE_{az} – RCGFC_c) * MR_{ua}]$

If CRCGSC > 0 and $[RCGSC_c – SUM_s(MCPE_{wz} * MR_{uw})] > 0$

Then:

PS_{ui} = $Max(0, \{RCGSC_c – SUM_s(MCPE_{wz} * MR_{uw})\text{-}CRCGSC\}$ / (# of instructed hours))

PO_{ui} = $SUM\ [(RCGMEC_c – MCPE_{jz}) * MIN\ (MINCAP_u/4, MR_{uj})]_j$

If CRCGSC ≤ 0

Then:

PS_{ui} = $[Max\ (0, RCGSC_c – (SUM_s(MCPE_{wz} * MR_{uw})))]$ / (# of instructed hours)

PO_{ui} = $SUM\ [(RCGMEC_c – MCPE_{jz}) * MIN\ (MINCAP_u/4, MR_{uj}\ )]_j$

The equation below will be used to determine the Total OOM Capacity Payments to be allocated to each QSE as described in Section 6.9.7.1, OOM Capacity Charge.

$$PC_{OOMRPi} \quad = \quad SUM\ (PC_{OOMRPqi})_q$$

Where:

a	Settlement Intervals beginning three (3) hours after the end of an OOMC Dispatch Instruction and continuing until the unit goes Off-line, the end of the Operating Day, or the next Resource-specific deployment, whichever occurs first
c	Resource Category
i	hourly interval
j	Settlement Intervals within the hourly interval, i
q	QSE
s	This variable shall represent the 15-minute Settlement Intervals as described in paragraph (2)(c) of Section 6.8.2.2, taking into consideration if the Generation Resource is a Quick Start Unit
u	single Resource
w	Settlement Interval prior to the Dispatch Instruction
z	zone
BP_{RPqui}	Bid Price for Replacement Reserve ($/MW) of the unit per interval
$C_{OOMRPui}$	Out of Merit Replacement Reserve Capacity awarded capacity (MW) per single Resource per interval
CRCGSC	Charge against the Resource Category Generic Startup Cost due if the generation unit continues to run past a Dispatch Instruction
$MCPE_{az}$	Market Clearing Price for Energy during a Settlement Interval between the end of a Dispatch Instruction and the unit going Off-line, the end of the Operating Day, or the next OOMC deployment, whichever occurs first
$MCPE_{jz}$	Market Clearing Price for Energy during a Settlement Interval within the hourly interval, i
$MCPE_{wz}$	Market Clearing Price for Energy for a Settlement Interval prior to the Dispatch Instruction
$MINCAP_u$	Generating unit LSL as reported in the Resource Plan
MR_{ua}	Actual metered output of the Resource during a Settlement Interval between the end of a Dispatch Instruction and the unit going Off-line, the end of the Operating Day, or the next OOMC deployment, whichever occurs first
MR_{uj}	Actual metered output of the Resource during a Settlement Interval within the hourly interval, i
MR_{uw}	Actual metered output of the Resource for a Settlement Interval prior to the Dispatch Instruction
PC_{OOMRPi}	Summation of Out of Merit Order (OOM) Replacement Capacity Payment ($) per interval for all QSEs in the market
$PC_{OOMRPqi}$	Total OOM Replacement Reserve Capacity Payment ($) by interval for that QSE (All OOM single Resources added together for that QSE)
$PC_{OOMRPqui}$	OOM Replacement Reserve Capacity Payments by single Resource by interval for that QSE
PO_{ui}	Price for operating a unit that is selected OOM to provide Balancing Energy

PS_{ui}	Price for starting a unit that is selected OOM to provide Balancing Energy
$RCGFC_c$	Resource Category Generic Fuel Cost for a specific category for upward instructions
$RCGMEC_C$	Resource Category Generic Minimum Energy Cost for a specific category of generation unit
$RCGSC_c$	Resource Category Generic Startup Cost for a specific category of generation unit

6.8.2.3 Energy Payments

(1) Whenever a Generation Resource is called for OOME Up or Zonal OOME Up, the QSE will receive any Resource Imbalance payment it is entitled to receive as specified in Section 6.8.1.13, Resource Imbalance. In addition, an OOME payment adjustment will be made such that the resulting total payment to the Resource(s) is equal to the higher of either: (a) RCGFC for the Resource(s); or (b) the MCPE for the Congestion Zone.

(2) The calculation for Generation Resources OOME Up or Zonal OOME Up is as follows:

$$\mathbf{PE_{OOMUPiq} = SUM\ (PE_{OOMUPiuq})_{uq} + SUM\ (PE_{OOMUPivq})_{vq}}$$

Where:

$$\mathbf{PE_{OOMUPiuq} = -1 * E_{OOMUPiuq} * Max\ [(RCGFC_c - MCPE_{iz}), 0]}$$

$$E_{OOMUPiuq} = \text{Max}\ (0, \text{Min}\ ((MR_{iuq} - OL_{iuq}), I_{OOMUPiuq}))$$

$$\mathbf{PE_{OOMUPivq} = -1 * E_{OOMUPivq} * Max\ [(RCGFC_c - MCPE_{iz}), 0]}$$

$$E_{OOMUPivq} = \text{Max}\ (0, \text{Min}\ ((MR_{ivq} - OL_{ivq}), NETUEQ_{ivq})) * OOMAGR_{ivq}$$

The equation below will be used to determine the Total OOM Energy Payments to be allocated to each QSE in Section 6.9.7.2, OOM Energy Charge.

$$PE_{OOMUPi} = SUM\ (PE_{OOMUPiu}) + SUM\ (PE_{OOMUPiv})$$

$$NETUEQ_{ivq} = \text{Max}(0,((NETOOMUEQ_{ivq} + NETLBEUQ_{ivq}) - (NETOOMDEQ_{ivq} + NETLBEDQ_{ivq}))$$

$$NETOOMUEQ_{ivq} = \text{Max}(0, (SUM(I_{OOMUPqui})_u - SUM(I_{OOMDNqui})_u))$$

$$NETLBEUQ_{ivq} = \text{Max}(0, (SUM(LBEUQ_{qui})_u - SUM(LBEDQ_{qui})_u))$$

$$NETOOMDEQ_{ivq} = \text{Max}(0, (SUM(I_{OOMDNqui})_u - SUM(I_{OOMUPqui})_u))$$

$$NETLBEDQ_{ivq} = \text{Max}(0, (SUM(LBEDQ_{qui})_u - SUM(LBEUQ_{qui})_u))$$

$OOMAGR_{ivq}$ = $[SUM(I_{OOMUPqui})_u + SUM(I_{OOMDNqui})_u] / [SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u + SUM(I_{OOMUPqui})_u + SUM(I_{OOMDNqui})_u]$

Where:

c	Resource category
i	interval
u	individual Generation unit (including units within an Aggregated Unit)
v	Aggregated Unit
z	zone
q	QSE
$MCPE_{iz}$	Market Clearing Price for Energy for that interval of the zone in which unit resides
$PE_{OOMUPiuq}$	OOME Up Payment ($) for that interval per unit per QSE
$PE_{OOMUPivq}$	OOME Up Payment ($) for that interval per Aggregated Unit per QSE
$PE_{OOMUPiq}$	OOME Up Payment ($) for that interval per QSE
PE_{OOMUPi}	Summation of OOME Up Payment ($) per interval for all QSEs in the market
$E_{OOMUPiuq}$	OOM Up quantity deployed for that unit per interval per QSE
$E_{OOMUPivq}$	OOM Up quantity deployed for that Aggregated Unit per interval per QSE
$I_{OOMUPiuq}$	OOM Energy Up Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (four (4) per hour for 15-minute Settlement Interval)
$I_{OOMDNiuq}$	OOM Energy Down Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (four (4) per hour for 15-minute Settlement Interval)
MR_{iuq}	Meter reading for that unit for that interval per QSE
MR_{ivq}	Meter reading for that Aggregated Unit for that interval per QSE.
OL_{iuq}	Resource Plan output level submitted by the QSE for the specific unit given the OOM instruction for that interval
OL_{ivq}	Resource Plan output level submitted by the QSE for the Aggregated Unit containing the specific unit given the OOM instruction for that interval.
$RCGFC_c$	Resource Category Generic Fuel Cost for a specific category
$NETOOMUEQ_{ivq}$	The net of all unit-specific OOM instructions (Up minus Down) that result in a positive value
$NETLBEUQ_{ivq}$	The net of all unit-specific Local Balancing Energy Instructions (Up minus Down) that result in a positive value
$NETOOMDEQ_{ivq}$	The net of all unit-specific OOM instructions (Down minus Up) that result in a positive value
$NETLBEDQ_{ivq}$	The net of all unit-specific Local Balancing Energy Instructions (Down minus Up) that result in a positive value
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions for that interval per specific unit
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions for that interval per specific unit
$NETUEQ_{iv}$	The overall net direction per the instructions given to the Aggregated Unit results in an up direction

$OOMAGR_{iv}$ The percentage of the aggregated instructions to the Aggregated Unit that represents the OOM Energy market

(a) The Nodal Market implementation requires Early Delivery System (EDS) testing. During the EDS 3 R6.3 Load Frequency Control (LFC) testing as documented by ERCOT's issuance of Dispatch Instructions to perform the test, the formula in paragraph (2) above will be modified in the following way:

$$I_{OOMUPiuq} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$I_{OOMDNiuq} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEUQ_{qui} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEDQ_{qui} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

Where:

$I_{OOMUPiuq}$	OOM Energy Up Instructions - The Generation Resource's aggregated MW output level for the Resource produced by the Security Constrained Economic Dispatch (as defined in the ERCOT Nodal Protocols; hereinafter, "SCED") process (Base Point) for the 15-minute Settlement Interval corresponding with an OOME Up deployment
$I_{OOMDNiuq}$	OOM Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Down deployment
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Up deployment.
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an Local Balancing Energy Down deployment.
BP_{y}	Base Point by interval - The Base Point generated from the SCED test system for the Generation Resource for the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred
$TLMP_{y}$	Duration of SCED interval per interval - The duration of the portion of the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred
y	A SCED interval in the Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred
i	15-minute Settlement Interval
u	Individual generation unit (including units within an Aggregated Unit)

q QSE

(i) During EDS 3 R6.3 LFC testing, when a combined cycle Generation Resource receives SCED Base Points at the Combined Cycle Configuration (as defined in the ERCOT Nodal Protocols) level, ERCOT will use MW telemetry based splitting percentages to allocate any OOME or Local Balancing Energy Instructions, as calculated in paragraph (2)(a) above, to each individual unit that makes up the Combined Cycle Configuration for each 15-minute Settlement Interval.

(ii) If, after receiving the Initial Statement for the Operating Day on which EDS 3 R6.3 LFC testing occurred as documented by Dispatch Instruction(s) to the QSE for a specific test period, a QSE does not agree with the updated Instructed Output level or payment for OOME or Local Balancing Energy, a QSE may submit a settlement and billing dispute in accordance with the process outlined in Section 9.5, Settlement and Billing Dispute Process. In addition to the standard information required on the dispute form, the dispute should clearly reference the EDS 3 R6.3 LFC test and indicate the disputed Settlement Intervals involved in the test.

(3) If ERCOT sends a Resource-specific Dispatch Instruction for OOME Up or Zonal OOME Up Service and the payment for OOME Service does not cover all costs of providing the service, then that QSE may submit verifiable, additional costs directly attributable to the OOME Dispatch Instruction, which exceed the payment for OOME Service calculated pursuant to paragraph (2) above. Verifiable costs are subject to the approved documentation requirements in paragraph (4)(h) below. These costs may include the cost of exceeding swing gas contract limits, additional gas Demand costs set by the fuel supply or transportation contracts, nodal implementation surcharge, and any additional costs to purchase emissions allowances or other costs incurred due to environmental regulations. Verification of these costs must be submitted to ERCOT by the QSE or the Resource to allow resolution by the end of the dispute process for Settlement True-Up as defined in Section 9.2.6, True-Up Statement.

(4) If a QSE requests cost-based recovery, the entire payment will be based solely on verifiable costs.

(a) After receiving the Initial Settlement Statement for the subject Operating Day, the QSE shall submit a settlement dispute in accordance with the dispute process outlined in Section 9.5. In addition to the standard information required on the dispute form on the ERCOT Portal, the dispute should clearly indicate:

(i) The Dispatch Instruction received from ERCOT to provide the OOME Services;

(ii) The payment received for providing the OOME Service;

(iii) The actual cost of providing the OOME Service; and

(iv) A reference to the documentation to be provided in writing as indicated in these Protocols.

(b) The QSE shall provide written documentation to allow ERCOT to verify the claimed amounts. All documentation submitted to ERCOT for verification pursuant to paragraph (4)(h) below shall be considered Protected Information in accordance with Section 1.3.1.1, Items Considered Protected Information.

(c) ERCOT shall not make payments for verifiable cost outside the defined documentation requirements until after the QSE has followed the steps outlined in paragraph (4)(h) below and the ERCOT Board has approved the documentation requirements.

(d) Fuel costs, including transportation and storage costs, will require supporting documentation of sufficient detail to allow for the verification of the cost of fuel consumed at the deployed Resource. Documentation may include contracts, invoices or other documents. For gas fired Resources, such documentation will not be required if the requested incremental fuel cost is less than one hundred ten percent (110%) of the FIP.

(e) For oil fired Resources, such documentation will not be required if the requested incremental fuel cost is less than one hundred ten percent (110%) of the FOP.

(f) For any Resource claiming NOx emissions allowances as part of the Operational Emission-related Cost, the Resource Entity may provide documentation supporting actual cost of emissions allowances used to comply with the OOME instruction. Such documentation will not be required if the requested emissions allowance cost is less than one hundred ten percent (110%) of the applicable NOxEAIP.

(g) The Resource Entity shall provide to ERCOT an attestation signed by an officer of the Resource Entity, in a form acceptable to ERCOT, specifying the type of fuel oil used.(h) Defined Documentation Requirements:

(i) Operational Fuel Cost for providing the OOME Service shall be determined by multiplying the change in instructed energy (MWh) due to the OOME instruction by the associated Marginal Heat Rate (MMBtu/MWh) and the associated fuel cost ($/MMBtu) of the instructed Resource for the intervals that the Resource was procured to provide the OOME Service.

(ii) The Marginal Heat Rate shall be determined by subtracting the total amount of fuel burn of the Resource (in MMBtu/hr) based on the planned output shown in the Resource Plan from the total amount of fuel burn (in MMBtu/hr) based on the lesser of the instructed level of the Resource or the actual Resource output, dividing the result by the net change in output level from the Resource Plan to the lesser of the instructed level of the Resource or the actual output of the unit (in MW). The amount of fuel consumed (in MMBtu) to provide OOME Service shall be calculated from the input/output curve coefficients or linear interpolation of test data points for the Resource from the most recently conducted heat rate tests filed with ERCOT. Test data shall be provided in sufficient detail to allow for the validation of the heat rate curve provided.

(iii) Operational Emission-related Cost shall be determined by multiplying the change in instructed energy (MWh) due to the OOME instruction by the associated marginal emission production rate (tons/MWh) by the associated emission allowance cost ($/ton) of the instructed Resource for the intervals covered by the OOME deployment. The marginal emission production rate shall be determined by subtracting the total amount of emission production of the Resource (tons/hr) based on the planned output shown in the Resource Plan from the total amount of emission production (in tons/hr) based on the lesser of the instructed level of the Resource or the actual Response output, dividing the result by the net change in output level from the Resource Plan to the lesser of the instructed level of the Resource or the actual output of the unit (MW).

The equation for this calculation is:

$$MEPR = [(Min(EP_{ACTUAL}, EP_{INST}) - EP_{SCH})/2000)]/[(Min(MW_{ACTUAL}, MW_{INST}) - MW_{SCH}]$$

Where,

EP_{ACTUAL} = Emission production rate based on actual Resource output during the OOME deployment (lbs/hour) as calculated below.

EP_{SCH} = Emission production rate based on scheduled Resource output in the Resource Plan during the OOME deployment (lbs/hour) as calculated below

EP_{INST} = Emission production rate based on instructed Resource output during the OOME deployment (lbs/hour) as calculated below

MW_{ACTUAL} = Actual MW loading of the Resource during the OOME deployment

MW_{SCH} = Scheduled MW loading of the Resource in the Resource Plan during the OOME deployment

MW_{INST} = Instructed amount of MW loading of the Resource by ERCOT during the OOME deployment

The amount of emissions production rate (EP_x) to provide OOME Service shall be calculated from the certified emission rate curve for the Resource. The equation of the certified emission rate curve is:

$CEC_R = A + (B*x) + (C*x^2) + (D*x^3) + (E*x^4)$

Where,

CEC = Certified Emission Curve (lbs/MMBtu/hour)

A, B, C, D and E are coefficients specific to the Resource

R = Resource

x = MW

Such that:

$EP_x = CEC_R * F_{Rx}$

Where,

EP_x = Emission production rate based on the Resource output (lbs/hour)

x = Resource output to use in CEC_R for Actual, Scheduled and Instructed (MW)

CEC_R = Certified Emission Rate Curve (tons/MMBtu/hour)

F_{Rx} = Fuel consumed on the Resource at the Actual, Scheduled and Instructed levels determined from the Resource I/O curve (MMBtu)

This emission rate curve shall be certified by an officer of the Resource owner as being accurate and representative of the Resource emissions and filed with ERCOT and may be different for each different emission product.

(A) The equation for calculation of the Operational Emissions-related Cost for NOx emissions (OEC_{NOX}) for an OOME deployment is:

$OEC_{NOX} = E_{OOME} * MEPR_{NOX} * EAC_{NOX}$

Where:

E_{OOME} = Incremental energy produced due to the OOME deployment (MWh)

$MEPR_{NOX}$ = Marginal NOx Emission Production Rate as calculated in above paragraph iii equations (tons/MWh)

EAC_{NOX} = Actual NOx emissions allowance cost or NOxEAIP ($/ton) whichever is applicable

(iv) ERCOT nodal implementation surcharge for providing OOME Service shall be calculated by multiplying the change in instructed energy (MWh) due to the OOME instruction by the Nodal surcharge factor (NODSF) ($/MWh).

(v) Compensation for types of cost, whose documentation requirements are not covered in paragraphs (4)(h)(i) through (4)(h)(iv) above for the deployed Resource, will be denied pending possible review by the ERCOT Board. The requesting QSE may request approval of the documentation requirements by the ERCOT Board, and if requested will be considered by the ERCOT Board at its next regularly scheduled meeting for which proper notice may be posted following ERCOT's receipt of the request. The requesting party may request that this review be conducted at an Executive Session of the ERCOT Board. Requests must be presented in person by a representative of the company submitting the request and must also include language suitable to be included in the Protocols to define the documentation requirements for future requests of a similar nature. Subsequent to the approval of such costs, the requesting company shall submit a PRR, in accordance with Section 21, Process for Protocol Revision, incorporating the necessary documentation standards provided to the ERCOT Board. Once approved by the ERCOT Board, ERCOT will process the request for payments as described in Section 9.2.5, Resettlement Statement.

(vi) Submit a signature sheet signed by the Authorized Representative of the Resource Entity certifying the costs submitted are directly attributable to the OOME deployment and which satisfies the documentation standards in Section paragraph (4)(h) above.

(5) Whenever a Generation Resource is called on for OOME Down or Zonal OOME Down, the QSE will be paid an energy payment equal to the total amount of energy to be reduced by the Resource, multiplied by the greater of: (a) the difference between (i) the MCPE of the Congestion Zone and (ii) the RCGFC for that Resource or (b) $0.00. The calculation for OOME Down is as follows:

$$\mathbf{PE_{OOMDNiuqz} = -1 * E_{OOMDNiu} * Max\ (0,(MCPE_{iz}-RCGFC_c))}$$

$$E_{OOMDNiu} = Max\ (0, Min((OL_{uiq} - MR_{iu}), I_{OOMDNiuq}))$$

$$\mathbf{PE_{OOMDNivqz} = -1 * E_{OOMDNiv} * Max\ (0,(MCPE_{iz}-RCGFC_c))}$$

$$E_{OOMDNiv} = Max\ (0, Min((OL_{ivq} - MR_{ivq}), NETDEQ_{ivq})) * OOMAGR_{ivq}$$

$$PE_{OOMDNiq} = SUM\ (PE_{OOMDNiu})_q + SUM\ (PE_{OOMDNiv})_q$$

$$PE_{OOMDNiz} = SUM\ (PE_{OOMDNiu})_z + SUM\ (PE_{OOMDNiv})_z$$

The equation below will be used to determine the Total OOM Down or Zonal OOM Down Payments to be allocated to each QSE in Section 6.9.7.2.

$$PE_{OOMDNi} = SUM\ (PE_{OOMDNiq})q$$

$$NETDEQ_{ivq} = Max\ [0, ((NETOOMDEQ_{ivq} + NETLBEDQ_{ivq}) – (NETOOMUEQ_{ivq} + NETLBEUQ_{ivq}))]$$

$$NETOOMUEQ_{ivq} = Max(0, (SUM(I_{OOMUPqui})_u – SUM(I_{OOMDNqui})_u))$$

$$NETLBEUQ_{ivq} = Max(0, (SUM(LBEUQ_{qui})_u – SUM(LBEDQ_{qui})_u))$$

$$NETOOMDEQ_{ivq} = Max(0, (SUM(I_{OOMDNqui})_u – SUM(I_{OOMUPqui})_u))$$

$$NETLBEDEQ_{ivq} = Max(0, (SUM(LBEDQ_{qui})_u – SUM(LBEUQ_{qui})_u))$$

$$OOMAGR_{ivq} = [SUM(I_{OOMUPqui})_u + SUM(I_{OOMDNqui})_u] / [SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u + SUM(I_{OOMUPqui})_u + SUM(I_{OOMDNqui})_u]$$

Where:

c	Resource category
i	interval
u	individual Generation unit (including units within an Aggregated Unit)
v	Aggregated Unit
z	zone
q	QSE
$PE_{OOMDNiuqz}$	OOME Down Payment ($) for that interval per unit for the QSE
$PE_{OOMDNivqz}$	OOME Down Payment ($) for that interval per Aggregated Unit per QSE
$PE_{OOMDNiq}$	Total OOME Down Payment in the interval for the QSE
$PE_{OOMDNiz}$	OOME Down Payment ($) per interval per zone
$PE_{OOMDNiv}$	OOME Down Payment ($) per interval per zone to Aggregated Units
$E_{OOMDNiu}$	OOM Energy quantity instructed down for that unit per interval
$E_{OOMDNiv}$	OOM Energy quantity instructed down for that Aggregated Unit per interval
$MCPE_{iz}$	Market Clearing Price for Energy per interval for that zone
$I_{OOMUPiuq}$	OOM Energy Up Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
$I_{OOMDNiuq}$	OOM Energy Down Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
MR_{iu}	Meter reading per unit per interval
MR_{iv}	Meter reading per Aggregated Unit per interval
OL_{iuq}	Resource Plan submitted by the QSE for the specific unit given the OOM instruction for that interval

OL_{ivq}	Resource Plan submitted by the QSE for the Aggregated Unit containing the individual unit(s) given the OOM instruction for that interval
$RCGFC_{c}$	Resource Category Generic Fuel Cost for a specific category as defined in Section 6.8.2, Capacity and Energy Payments for Out-of-Merit or Zonal OOME Service
PE_{OOMDNi}	Total OOM Down Energy Payments
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions for that interval per specific unit
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions for that interval per specific unit
$NETOOMUEQ_{ivq}$	The net of all unit-specific OOM instructions (Up minus Down) that result in a positive value
$NETLBEUQ_{ivq}$	The net of all unit-specific Local Balancing Energy Instructions (Up minus Down) that result in a positive value
$NETOOMDEQ_{ivq}$	The net of all unit-specific OOM instructions (Down minus Up) that result in a positive value
$NETLBEDQ_{ivq}$	The net of all unit-specific Local Balancing Energy Instructions (Down minus Up) that result in a positive value
$NETDEQ_{iv}$	The overall net direction per the instructions given to the Aggregated Unit results in a down direction
$OOMAGR_{iv}$	The percentage of the aggregated instructions to the Aggregated Unit that represents the OOM Energy market

(a) The Nodal Market implementation requires EDS testing. During the EDS 3 R6.3 LFC testing as documented by ERCOT's issuance of Dispatch Instructions to perform the test, the formula in paragraph (5) above will be modified in the following way:

$$I_{OOMUPiuq} = 1/4 * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$I_{OOMDNiuq} = 1/4 * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEUQ_{qui} = 1/4 * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEDQ_{qui} = 1/4 * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

Where:

$I_{OOMUPiuq}$	OOM Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Up deployment
$I_{OOMDNiuq}$	OOM Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Down deployment
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement

Interval corresponding with a Local Balancing Energy Up deployment

$LBEDQ_{qui}$ Local Balancing Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an Local Balancing Energy Down deployment

BP_y Base Point by interval - The Base Point generated from the SCED test system for the Generation Resource for the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred

$TLMP_y$ Duration of SCED interval per interval - The duration of the portion of the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.

y A SCED interval in the Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred

i 15-minute Settlement Interval

u Individual generation unit (including units within an Aggregated Unit)

q QSE

(i) During EDS 3 R6.3 LFC testing, when a combined cycle Resource receives SCED Base Points at the Combined Cycle Configuration (as defined in the ERCOT Nodal Protocols) level, ERCOT will use MW telemetry based splitting percentages to allocate the OOME or Local Balancing Energy Instructions, as calculated in paragraph (5)(a) above, to each individual unit that makes up the Combined Cycle Configuration for each 15-minute Settlement Interval.

(ii) If, after receiving the Initial Statement for the Operating Day on which EDS 3 R6.3 LFC testing occurred as documented by Dispatch Instruction(s) to the QSE for a specific test period, a QSE does not agree with the updated Instructed Output level or payment for OOME or Local Balancing Energy, a QSE may submit a settlement and billing dispute in accordance with the process outlined in Section 9.5. In addition to the standard information required on the dispute form, the dispute should clearly reference the EDS 3 R6.3 LFC test and indicate the disputed Settlement Intervals involved in the test.

(6) If a wind Resource is called upon to provide OOME Down Service and the normal payment for OOME Service is insufficient to cover actual verifiable costs of providing the service, then that Resource may file a claim with ERCOT to be paid the lower of:

(a) All verifiable costs that are directly attributable to the OOME service; or

(b) MaxCap * CCF * Curtail% * Hrs *CRP

Where:

MaxCap:	Registered Maximum Capacity of the Resource (MW)
CCF:	Capacity Conversion Factor as defined at thirty precent (30%)
Curtail%:	Set at fifteen percent (15%) for the period July 1, 2002 through June 30, 2003; ten percent (10%) for the period July 1, 2003 through June 30, 2004; and five percent (5%) from July 1, 2004 and thereafter
Hrs:	Total number of hours in the month
CRP:	Price paid for curtailment, $27/MWh

The verifiable costs of providing the service shall be provided to ERCOT in writing from the QSE, certified by an Authorized Representative of the Resource and within a timeframe to allow resolution by the end of the dispute process for Settlement True-Up. Verifiable costs under paragraph (a) above shall be based on the actual verifiable MW production that the unit could have produced based on actual operating and maintenance conditions and actual wind speeds. Verifiable costs must be established in order for a claim to be valid even if paid under paragraph (b) above.

A wind Resource filing a claim under this paragraph (6) must provide actual production and actual wind speed data for the entire month of the claim. ERCOT will review this data for all hours of the month. In the event ERCOT determines that it paid the Resource for any OOME down service in any hour of the month that the actual wind speed data show could not have actually been provided, then ERCOT shall deduct any such excess payment from the payment otherwise payable under paragraph (a) or (b) above. A wind Resource filing a claim under this paragraph (6) shall also provide an affidavit indicating that the wind Resource, or its Affiliate(s), has tax liability sufficient to fully utilize any lost credits claimed to offset taxes for the year in which the credit would have been received.

This provision will expire at the earlier of:

(i) December 31, 2006;

(ii) When ERCOT implements direct assignment of Local Congestion costs in accordance with the Public Utility Commission of Texas (PUCT) Order on Rehearing in Docket No. 23220, *Petition of the Electric Reliability Council of Texas (ERCOT) for Approval of the ERCOT Protocols*; or

(iii) Within one (1) month after accumulated verifiable costs paid under this paragraph (6) reach ten million dollars ($10,000,000).

(7) Whenever a Load acting as a Resource (LaaR) is called for OOME Up, the QSE will receive an OOME payment of the instructed amount of OOME Up provided by the Load acting as a Resource multiplied by a price equal to item (a) minus item (b), as defined below:

(a) The lower of the:

(i) Sum of the bid premium submitted by the specific LaaR and the MCPE for the Congestion Zone; or

(ii) The OOME Up Price.

(b) The MCPE for the Congestion Zone.

OOME Up Price is determined by multiplying the Fuel Index by the appropriate Heat Rate. The Heat Rate will be set at eighteen (18) MMBtu / MWh.

The FIP shall be the midpoint price expressed in $ / MMBtu, published in Gas Daily, in the Daily Price Survey, under the heading "East-Houston-Katy, Houston Ship Channel" for the day of OOME deployment. The FIP for Saturdays, Sundays, holidays, and other days for which there is no FIP published in Gas Daily, shall be the next published FIP after the day of OOME deployment. In the event that the FIP is not published for more than two (2) days, the previous day published FIP will be used for Initial Settlement and the next day published FIP will be used for true up of the Final Statement.

The calculation for OOME Up for LaaRs is as follows:

$$\mathbf{PE_{OOMUPiq} = SUM\ (PE_{OOMUPiuq})_{uq}}$$

Where:

$$\mathbf{PE_{OOMUPiuq} = -1 * E_{OOMUPiuq} * [Max\ [Min\ ((FI * HR), (BP_{iuq} + MCPE_{iz})), MCPE_{iz}] - MCPE_{iz}]}$$

$$E_{OOMUPiuq} = \text{Max}\ (0, \text{Min}\ (OL_{iuq} - LAARTOT), I_{OOMUPiu}))$$

The equation below will be used to determine the Total OOM Energy Payments to be allocated to each QSE in Section 6.9.7.2.

$$PE_{OOMUPi} = SUM(PE_{OOMUPiu})$$

Where:

i	interval
q	QSE
u	unit
z	zone
FI	Fuel Index ($/Btu)
HR	The standard Heat Rate for OOM of a LaaR is eighteen (18) MMBtu
$E_{OOMUPiuq}$	OOM Up quantity deployed for that unit per interval per QSE
$I_{OOMUPiu}$	The difference between the Resource Plan and the OOM Energy Up Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (four (4) per hour for 15 minute Settlement Interval)
BP_{iuq}	Actual Bid Premium Up bid price submitted by the specific LaaR

LAARTOT	Actual Electric Service Identifier (ESI ID) usage
$MCPE_{iz}$	Market Clearing Price for Energy for that interval of the zone in which unit resides
OL_{iuq}	Resource Plan output level submitted by the QSE for the specific Resource given the OOM instruction for that interval
PE_{OOMUPi}	Summation of OOME Up Payment ($) per interval for all QSEs in the market
$PE_{OOMUPiq}$	OOME Up Payment ($) for that interval per QSE
$PE_{OOMUPiuq}$	OOME Up Payment ($) for that interval per unit per QSE

If a LaaR is called to provide OOME Up service and the payment for OOME service is insufficient to cover all costs of providing the Service, then that LaaR will be paid, in addition to the energy payment, all verifiable costs in excess of the OOME payment that are directly attributable to the OOME Service. These costs may include the cost of lost raw material, product rendered unusable, idled labor, clean up cost associated with the deployment required to restart production. In addition incremental production cost such as labor, energy and material, as well as any incremental energy cost associated with running backup generation may also be included. Idled labor will only be allowed if the OOME instruction is longer than three (3) hours in duration. Such payment will not exceed one thousand dollars ($1000) per MWh for the duration of the deployment plus an additional restart period not to exceed three (3) hours. Verification of these costs must be submitted to ERCOT to allow resolution by the end of the dispute process for Settlement True-Up as defined in Section 9.2.6, True-Up Statements.

Compensation for types of cost, whose documentation requirements are not outlined in this paragraph (7), must be reviewed and approved by the ERCOT Board of Directors during an Executive Session of their next regularly scheduled meeting. Requests must be presented in person by a representative of the company submitting the request and must also include language suitable to be included in the Protocols to define the documentation requirements for future requests of a similar nature. Subsequent to the approval of such costs, the requesting company shall submit a PRR, in accordance with Section 21 incorporating the necessary documentation standards provided to the ERCOT Board. Once approved by the ERCOT Board, ERCOT will process payments for such cost on a Resettlement Statement as described in Section 9.2.5.

6.8.2.4 Aggregating Units

(1) Generation Entities in ERCOT may choose to request that ERCOT allow the Generation Resource to aggregate, for settlement purposes, two (2) or more individual units located at a single location if the operation of those units requires that an interdependent and coordinated relationship is maintained (for example, combined cycle operation).

(2) ERCOT will review requests to have individual units aggregated into an Aggregated Unit for settlement purposes and will determine if the aggregation can be performed without negative impact to ERCOT's operations. Criteria ERCOT will use include, but are not limited to: (i) evaluation of Shift Factors of the units to be aggregated relative to Local

Congestion in the same zone as the units to be aggregated; and (ii) whether the individual units connect to the same bus. ERCOT shall have the sole discretion whether to approve the request to treat individual units as an Aggregated Unit for settlement purposes.

(a) Requests for site-specific aggregation of units shall be prepared by the QSE representing the Generation Entity for the units using the appropriate form posted on the ERCOT MIS. Once ERCOT approves aggregating the units into an Aggregated Unit for settlement purposes, the units may not be requested to be disaggregated for three hundred sixty-five (365) days from the date on which ERCOT approved the Aggregated Unit.

(b) Treatment of individual generation units as an Aggregated Unit shall be for settlement purposes only and ERCOT's Control Area Operators and its operations system and staff will continue to treat the individual units as individual units and will not recognize Aggregated Units. By way of example only, ERCOT will continue to perform its reliability studies based on individual units and send Dispatch Instructions to individual units within an Aggregated Unit.

(3) Once ERCOT approves the Aggregated Unit, ERCOT shall have fifteen (15) Business Days to establish the relationships in its settlement process to correctly settle the units as an Aggregated Unit. The effect of the aggregation will be that all schedules, instructions, and actual metered output for the individual units of an Aggregated Unit will be added and ERCOT will use the sum in its settlement calculations for the QSE representing the Aggregated Unit.

(4) Specifically:

$$E_{OOMUPivq} = Sum(E_{OOMUPiuq})$$

$$I_{OOMUPiv} = Sum(I_{OOMUPiu})$$

$$MR_{ivq} = Sum(MR_{iuq})$$

$$OL_{ivq} = Sum(OL_{iuq})$$

$$E_{OOMDNivq} = Sum(E_{OOMDNiuq})$$

$$I_{OOMDNiv} = Sum(I_{OOMDNiu})$$

Where:

i	interval
u	individual generation unit (including units within an Aggregated Unit).
v	Aggregated Unit
q	QSE
$E_{OOMUPiuq}$	OOM Up quantity deployed for each unit in the Aggregated Unit per interval per QSE.
$E_{OOMUPivq}$	OOM Up quantity deployed for the Aggregated Unit per interval per QSE.

$I_{OOMUPiu}$	OOM Energy Up Instructions for that interval for that unit converted to MWh for that interval by dividing by the number of intervals per hour (4 per hour for 15 minute Settlement Intervals).
$I_{OOMUPiv}$	OOM Energy Up Instructions for that interval for that Aggregated Unit converted to MWh for that interval by dividing by the number of intervals per hour (4 per hour for 15 minute Settlement Intervals).
MR_{iuq}	Meter Reading for that unit for that interval per QSE.
MR_{ivq}	Meter Reading for that Aggregated Unit for that interval per QSE
OL_{iuq}	Resource Plan output level submitted by the QSE for the specific unit given the OOM instruction for that interval.
OL_{ivq}	Resource Plan output level submitted by the QSE for the Aggregated Unit containing the individual unit(s) given the OOM instruction for that interval.
$E_{OOMDNiuq}$	OOM Down quantity deployed for each unit in the Aggregated Unit per interval per QSE
$E_{OOMDNivq}$	OOM Down quantity deployed for the Aggregated Unit per interval per QSE
$I_{OOMDNiu}$	OOM Energy Down Instructions for that interval for the unit converted to MWh for that interval by dividing by the number of intervals per hour (4 per hour for 15 minute Settlement Intervals)
$I_{OOMDNiv}$	OOM Energy Down Instructions for that interval for that Aggregated Unit converted to MWh for that interval by dividing by the number of intervals per hour (4 per hour for 15 minute Settlement Intervals)

6.8.2.5 Settlement of Zonal OOME Deployments

(1) QSEs responding to Zonal OOME Up Dispatch Instructions will be paid OOME Up payments as set forth in Section 6.8.2.3, Energy Payments, paragraph (2). The Resource-specific OOME Up payment for such Resource(s) will be included on the Initial Statement for the applicable Operating Day. If ERCOT cannot timely prepare and import the billing determinants required to settle Zonal OOME Up prior to the issuance of the Initial Statement, ERCOT will settle the Zonal OOME Up Dispatch Instructions on the Final Statement for the affected Operating Day. ERCOT will calculate the OOME Up payment based on the Generation Resource(s) that generated above its planned output level as indicated in the QSE's Resource Plan. If the QSE does not provide the total instructed amount of Zonal OOME Up Service, the QSE will be compensated for only the amount of the Zonal OOME Dispatch Instruction actually provided.

(2) QSEs responding to Zonal OOME Down Dispatch Instructions will be paid OOME Down payments as set forth in Section 6.8.2.3, Energy Payments, paragraph (5). The Resource-specific OOME Down payment for such Resource(s) will be included on the Initial Statement for the applicable Operating Day. If ERCOT cannot timely prepare and import the billing determinants to settle Zonal OOME Down prior the issuance of the Initial Statement, ERCOT will settle the Zonal OOME Down Dispatch Instructions on the Final Statement for the affected Operating Day. ERCOT will calculate the OOME Down payment based on the Generation Resource(s) that generated below its planned

output level as indicated in the QSE's Resource Plan. If the QSE does not provide the total instructed amount of Zonal OOME Down Service, the QSE will be compensated for only the amount of the Zonal Dispatch Instruction actually provided.

(3) Zonal OOME Up Service and Zonal OOME Down Service provided based on a Zonal Dispatch Instruction will not be subject to uninstructed Resource charges as described in Section 6.8.1.15.3, Uninstructed Charge Methodology and Equation.

6.8.2.6 Payment When a Resource Receives an OOME Down to Zero (0) MW Dispatch Instruction

(1) Resources that are issued Dispatch Instructions to provide OOME down service to zero (0) MW, and which actually shut down to follow such Dispatch Instructions, will be paid both the OOME cost defined in Section 6.8.2.3, Energy Payments, for the instructed interval(s) and Resource Category Generic Capacity Startup Cost for each instructed shut down. In order to receive payment under this Section, a QSE shall timely file a settlement and billing dispute pursuant Section 9.5, Settlement and Billing Dispute Process.

(2) The calculation of startup payment for the Resource that receives an OOME down Dispatch Instruction to provide service to zero (0) MW is:

$$\mathbf{PS_u = RCGSC_c}$$

Where:

PS_u	Startup payment for the Resource which receives an OOME down Dispatch Instruction to zero (0) MW
c	Resource Category
u	Single Resource
$RCGSC_c$	Resource Category Generic Startup Cost for a specific category of generation unit

(3) If ERCOT sends a QSE a Resource-specific Dispatch Instruction for OOME down to zero and the payment above does not cover all costs of providing the service, then that QSE may submit verifiable, additional costs directly attributable to providing the service, which exceed the payment for the service calculated pursuant to this Section. The QSE will be paid only for additional costs directly attributable to providing the service. Verifiable costs are subject to the approved documentation requirements in this Section. Verification of these costs must be submitted to ERCOT by the QSE or the Resource to allow resolution by the end of the dispute process for settlement true-up as defined in Section 9.2.6, True-Up Statement.

(4) QSEs requesting cost based recovery as described in this Section shall, after receiving the Initial Statement for the subject Operating Day, submit a settlement dispute in accordance with the dispute process outlined in Section 9.5, Settlement and Billing Dispute Process.

In addition to the standard information required on the dispute form on the ERCOT Portal, the dispute should clearly indicate:

(a) The Dispatch Instruction received from ERCOT to provide the services;

(b) The payment received for providing the service;

(c) The actual cost of providing the service; and

(d) A reference to the documentation to be provided in writing.

(5) QSEs requesting cost based recovery shall also provide documentation to allow ERCOT to verify the claimed amounts. All documentation submitted to ERCOT for verification pursuant to this Section shall be considered Protected Information in accordance with Section 1.3.1.1, Items Considered Protected Information. ERCOT shall not make payments for verifiable costs outside the defined documentation requirements until after the QSE has followed the steps outlined in this Section and the ERCOT Board has approved the documentation requirements.

(6) Defined documentation requirements for this Section include: Variable non-fuel maintenance cost (in dollars per MWh) for a specific deployed Resource due to an SPS actuation, which shall be calculated based on actual itemized variable maintenance costs contained in contracts with a third party or the manufacturer's recommended maintenance schedule and associated costs. Supporting documentation will be the corresponding excerpt of the appropriate contract from the third party or the maintenance schedule.

(7) Compensation for additional types of verifiable costs not outlined above must be reviewed and approved by the ERCOT Board of Directors during an Executive Session of its next regularly scheduled meeting. Requests must be presented in person by a representative of the company submitting the request and must also include language suitable to be included in the Protocols to define the documentation requirements for future requests of a similar nature. Immediately subsequent to the approval of such costs, the requesting company shall submit a Protocol Revision Request (PRR), in accordance with Protocol Section 21, Process for Protocol Revision, incorporating the necessary documentation standards provided to the ERCOT Board.

6.8.3 Capacity and Energy Payments for RMR and Synchronous Service

RMR Units and MRA resources selected through the planning process, pursuant to Section 6.5.9.2, Exit Strategy from an RMR Agreement, providing services will be paid according to their Agreement.

6.8.3.1 Capacity Payments for RMR Service

(1) The hourly capacity payment for RMR Service is referred to in these Protocols as the "Standby Price." The hourly estimated Standby Price, which may vary monthly, is calculated as follows:

SB_{RMRemu} = [monthly estimated Eligible Costs]/h

Where:

e	estimated
m	month
u	unit
h	hours in the month
SB_{RMR}	price for Standby RMR Service

(2) The formula below is used to determine the total RMR Payments to be allocated to each QSE in Section 6.9.4, Settlement Obligation for Black Start Service, RMR Standby Service, and RMR Synchronous Condenser Service.

SB_{RMRi} = $SUM(SB_{RMRuhq})_q$ / n

Where:

i	interval
h	Hour
n	number of intervals in the hour
q	QSE
u	unit
SB_{RMRi}	Summation of RMR Standby Prices in that interval for all QSEs in the market
SB_{RMRuhq}	RMR Standby Price per unit (for that QSE) for that hour

(3) The hourly estimated Standby Price shall be based on the estimated Eligible Costs of the RMR Unit as contained in the RMR Agreement. The monthly estimate is adjusted to allow recovery of actual Eligible Costs prior to the True-Up Settlement Statement. An Incentive Factor is applied to the actual Eligible Costs (as part of the Standby Price), excluding fuel costs and nodal implementation surcharges, incurred by the RMR Unit in the provision of RMR Service. Actual cost data must be submitted on time by the Generation 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, actual cost data for month 'x' must be submitted thirty (30) days prior to the publishing date of the True-Up Settlement Statement for the first day in month 'x.

$SBRMR_{mu}$ = ((SP+/-A)*IF)/h

Where:

h	hours in the month
m	month
u	unit
A	Adjustment for actual Eligible Costs for the month
IF	1 + Incentive Factor as defined in Section 6.8.3.1(7) below
SP	Monthly estimated Standby Price

(4) "Eligible Costs" for annual RMR Agreements, RMR Agreements for the minimum agreement period and RMR Agreements under Section 6.5.9, Reliability Must-Run Service, item (5) for periods exceeding twelve (12) months are defined to be costs that would be incurred by the RMR Unit owner to provide the RMR Service, excluding fuel costs, above the costs the RMR Unit would have incurred anyway had it been mothballed or shut down. Examples of appropriate Eligible Costs include, but are not limited to, the following to the extent they each meet the standard for eligibility:

(i) Labor, materials, supplies and services necessary to operate the RMR Unit;

(ii) Costs associated with emissions credits or emissions reduction equipment;

(iii) Costs associated with maintenance due to either required equipment maintenance or replacement to alleviate unsafe operating conditions, regulatory requirements, or to ensure the ability to operate the RMR Unit consistent with Good Utility Practice;

(iv) Reservation and transportation costs associated with firm fuel supplies not recovered under Section 6.8.3.3, RMR Energy Payments Based on Contract Amounts;

(v) Property taxes and other taxes attributable to continuing to operate the RMR Unit;

(vi) Capital Expenditures and associated debt and interest cost, if applicable, required to keep the RMR Resource available for RMR as negotiated with ERCOT. The salvage value of any Capital Expenditure will be rebated to ERCOT at the end of the contract Term; and

(vii) The nodal implementation surcharge.

Examples of costs not included as Eligible Costs are:

(i) Depreciation expense for any Capital Expenditures incurred prior to the execution of an RMR , depreciation expense for any Capital Expenditures not approved in advance by ERCOT, debt and interest costs incurred prior to the execution of an RMR Agreement;

(ii) Property taxes and other taxes not attributable to continuing to operate the RMR Unit;

(iii) Labor costs associated with other, non-RMR Generation Resources at the same Facility; and

(iv) Any other costs the Generation Entity would have incurred even if the RMR Unit had been mothballed or shutdown.

(5) The owner of the RMR Unit shall provide good faith detailed estimates of its non-fuel Eligible Costs to ERCOT as part of the RMR Agreement negotiation process. ERCOT shall review and approve the budget and utilize these figures as the basis for Initial Settlement for RMR Service. Actual Eligible Costs incurred by the RMR Unit will be used for on subsequent Final, Resettlement, or True-Up Settlements as agreed upon in Section 6.8.3.1(6).

The non-fuel Eligible Cost budgeting process shall be as follows:

RMR Unit owner shall supply ERCOT a preliminary non-fuel Eligible Cost budget for the twelve (12) month period starting with the anticipated effective date of the RMR Agreement. The budget will include Eligible Costs categorized in terms of (i) Base Cost of Operations; (ii) Outage Maintenance Cost; (iii) Non Outage Maintenance Cost; and (iv) Other Budget Items, each of which are further defined as follows:

(i) "Base Cost of Operations" includes Eligible Costs that are independent of the levels of operation, Outages and non-Outage maintenance;

(ii) "Outage Maintenance Cost" includes Eligible Costs attributable to scheduled Outages and/or inspections occurring during the Term of the RMR Agreement. Maintenance alternatives available during any scheduled Outage will be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner will 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;

(iii) "Non-Outage Maintenance Cost" includes non-recurring Eligible Costs that are independent of a particular scheduled Outage. Non-Outage maintenance alternatives available during any scheduled Outage will be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner will 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; and

(iv) "Other Budget Items" include other Eligible Costs not clearly identifiable to the previous three categories.

Thirty (30) days after receipt of the preliminary non-fuel 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 will set the Target Availability consistent with the options presented to and selected during the budgeting process. The Target Availability shall be determined by taking into account a negotiated amount of predicted Forced Outages and Planned Outages identified during the budgeting process.

(6) The RMR Unit owner will provide ERCOT with actual Eligible Costs on a monthly basis in a level of detail sufficient for ERCOT to verify that all Eligible Costs are appropriate. ERCOT will perform a true-up of the estimated Eligible Costs using the submitted and verified actual Eligible Costs for the RMR Unit on a schedule determined during the RMR contract negotiations such that, for the duration of the RMR Agreement, the QSE for the RMR Unit is paid only for the actual Eligible Costs incurred. Documentation to be provided by an RMR Unit owner to allow ERCOT to verify submitted costs to ERCOT for payment will be based on mutual agreement between the RMR Unit owner and ERCOT or through specific documentation standards outlined in the Protocols. Absent specific documentation requirements mutually agreed to by the parties or outlined in the Protocols, the RMR Unit owner will provide an affidavit as verification attesting that the Eligible Costs figures being submitted are attributable to operating the RMR Unit.

(7) The Incentive Factor for all RMR Agreements is equal to ten percent (10.0%) of the actual non-fuel Eligible Costs incurred by the RMR Unit for the duration of the RMR Agreement. The Incentive Factor will be paid at the same time as the actual Eligible Costs as part of the final Standby Price. The Incentive Factor for RMR Agreements shall not be applied to the nodal implementation surcharge, any debt payment or interest costs. The Incentive Factor shall never be less than zero.

(8) The Incentive Factor payment shall be reduced if (*i*) the RMR Unit fails to perform to the contracted capacity during a Capacity Test as described in the RMR Agreement and (*ii*) if in ERCOT's reasonable determination, such reduction in capacity materially affects reliability. The reduction will be linear, with a two percent (2%) reduction in the Incentive Factor payment for every one percent (1%) of reduced capacity.

(9) 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 SCR equipment to meet NOx limitation requirements), ERCOT and the RMR Unit owner may negotiate an alternate estimated Standby Price and/or term longer than one (1) year.

(10) The Incentive Factor payment shall be reduced if the RMR Unit fails to perform at the Target Availability (i.e. the Actual Availability, as defined below, is less than the Target Availability), established during the budgeting process outlined in section 6.8.3.1 (5), for a rolling six (6) month average. The reduction will be linear; with a two percent (2%) reduction in Incentive Factor payment for every one percent (1%) that Actual Availability is less than the Target Availability of the contracted capacity. The RMR Unit's "Actual Availability" shall be calculated on an hourly rolling six-month average basis by dividing *(i)* the number of hours that the RMR Unit was available according to its Final Resource

Plan for each hour of the previous 4380 hours by *(ii)* 4380. If less than 4380 hours have elapsed since the start of the RMR Agreement ("Elapsed Time"), then, for each hour that Elapsed Time is less than 4380, that hour shall be considered as if the RMR Unit was available.

6.8.3.2 Capacity Payments for Synchronous Condenser Service

Any capacity provided by Synchronous Condensers will not be compensated.

[PIP128: The system is not configured to compensate for Synchronous Condenser Service.]

Synchronous Condenser Agreements are set annually. An economic model will be used, identical to RMR economic model defined above in Section 6.8.3.1, Capacity Payments for RMR Service, to determine the levelized (i.e., same cost each year) annual carrying costs of a then current simple-cycle gas turbine generator set (class and size to be defined to approximately equal the megawatts or megavolt-amps being contracted).

(1) The annual total costs derived from the economic model described above will be converted to an hourly cost by dividing it by eight thousand seven hundred sixty (8,760) hours.

(2) For Synchronous Condenser Units, the hourly cost derived in (1) is multiplied by twenty percent (20%) and divided by the nameplate megavolt-amps (MVA) size for the proxy unit. This yields the hourly standby price for Synchronous Condensers.

(3) The standby price may be reduced if the Synchronous Condenser Unit fails to perform at eighty-five percent (85%) availability for a rolling six (6) month average. The reduction will be linear, with a two percent (2%) reduction in standby fee for every one percent (1%) that availability is less than eighty-five percent (85%) of the contracted capacity.

(4) The settlement calculation to determine the Synchronous Condenser standby fee is as follows:

$$\mathbf{SSB_{qh} = SUM(SSB_{uhq})_u}$$

Where:

$SSB_{uh} = -1 * HrPrice * SCUCap_{uhi} * AvailRed_{uh}$

$SCUCap_{uh}$ Synchronous Condenser Unit Capacity is the capacity that is used in determining the Standby Fee based on contract MVA

$AvailRed_{uh} = IF (HrRollEAF_{uh} >=.85, 1, IF (HrRollEAF_{uh} >.35, (1 – ((.85 – HrRollEAF_{uh}) * 2)), 0))$

Availability Capacity Reduction is the reduction in Billing Capacity caused by the unit being less than eighty-five percent (85%) available on a rolling six month basis.

$HrRollEAF_{ui} = ((\sum_{h=1-4380} AvailSync_{uh}) / 4380)$

Hourly Rolling Equivalent Availability Factor over a rolling six month period.

$AvailSync_{ui}$ = Y; Available of service.

Where:

Y = 0 for unavailable service

Y = 1 for available service

MiscondChrg = IF (Excused = Yes, 0, 10000)

(5) The formula below will be used to determine the total Synchronous Condenser Payments to be allocated to each QSE in Section 6.9.4, Settlement Obligation for Black Start Service, RMR Standby Service, and RMR Synchronous Condenser Service.

$$\mathbf{SSB_i = SUM(SSB_{hq})_q / n}$$

Where:

h	hour
n	number of intervals in an hour
SSB_{uhq}	Synchronous Condenser Standby Payment per Unit per hour for that QSE
SSB_{qh}	Synchronous Condenser Standby Payment per hour to the QSE.
SSB_i	Summation of Synchronous Condenser Standby Payments per interval for all QSEs in the market
MiscondChrg	When not excused, currently set at ten thousand ($10,000) dollars per day.

Note: If less than 4380 hours have elapsed since the start date,
HrRollEAF = 1.0

6.8.3.3 RMR Energy Payments Based on Contract Amounts

(1) Fuel payments, on the Initial Settlement Statement, for energy delivered under the RMR Agreement will be based on the product of such energy delivered (in MWH) times an estimated RMR Unit heat rate, in MMBtu/MWh, times an estimated fuel price, in

$/MMBtu as included in the contract amount negotiated by the Generation Entity. The estimated fuel payments may also include a fuel adder to better approximate expected actual fuel costs. The fuel payment will be subsequently trued-up to reflect actual fuel costs as set forth in Section 6.8.3.3(4).

(2) The RMR Unit owner shall provide good faith estimates of the RMR Unit heat rate to ERCOT in its application for an RMR Agreement. 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 Resource. For each option, the RMR Unit owner will detail the associated impacts on the fuel and non-fuel budgets and on the availability of the unit. No less than thirty (30) days after the receipt of the fuel Supply options, ERCOT shall notify the RMR Unit owner of its fuel Supply option selection. Fuel payments on the Initial Settlement Statement for RMR Services provided will be based on the estimated heat rates, actual RMR energy deployments, and estimates of fuel costs established using the fuel Supply options selected by ERCOT. These payments will be trued up to reflect actual verifiable fuel costs incurred by the RMR Unit on subsequent Final, Resettlement or True-Up Statements as outlined in Section 6.8.3.3(4).

(3) The Generation Entity in good faith may revise the estimated fuel prices for its RMR Unit at any time to more accurately reflect the expected fuel expense for a particular day, subject to ERCOT's approval of the revised fuel price, which ERCOT shall not unreasonably withhold. This adjusted fuel price will be the basis for payment for energy delivered in the operating month, subject to true-up by ERCOT based on actual fuel costs incurred by the RMR Unit in providing RMR Service.

(4) 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 will perform a true-up of the estimated fuel costs using the submitted and verified actual fuel costs for the RMR Unit on a schedule determined during the RMR Agreement negotiations such that, for the duration of the RMR Agreement, the RMR Unit is paid only for its actual fuel costs incurred. 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. Documentation to be provided by an RMR Unit owner to allow ERCOT to verify submitted fuel costs to ERCOT for payment will be based on mutual Agreement between the RMR Unit owner and ERCOT or through specific documentation standards outlined in the Protocols. Absent specific documentation requirements mutually agreed to by the parties or outlined in the Protocols, the RMR Unit owner will provide an affidavit as verification attesting that the fuel cost figures being submitted represent fuel cost attributable to operating the RMR Unit.

(5) Fuel costs incurred by the RMR Unit to provide Balancing Energy Service will be excluded from the monthly fuel cost payment. The amount to be excluded will be calculated by multiplying the total actual fuel cost for the month by the monthly energy

produced for Balancing Energy Service and then divided by the total energy produced by the RMR Unit for the month.

(6) The formula below will be used to determine the total RMR Payments to be allocated to each QSE in Section 6.9.4, Settlement Obligation for Black Start Service, RMR Standby Service, and RMR Synchronous Condenser Service.

$$E_{RMRiq} = SUM(E_{RMRui})_q$$

Where:

i	interval
u	unit
q	QSE
E_{RMRiq}	Summation of payments for RMR Energy per interval for all QSEs in the market.
E_{RMRui}	Payment to provider for RMR Energy per unit per interval

6.8.3.4 Synchronous Condenser Hourly Operations Payment

There will be no compensation for the operations of Synchronous Condensers

[PIP128: System Design does not support compensation for any Synchronous Condenser Service.]

(1) For Synchronous Condenser Units, hourly operations payments shall be based upon the non-fuel variable O&M cost incurred when the unit operates and which is not recovered in the Standby Price as defined in item (1) of Section 6.8.3.1, Capacity Payments for RMR Service, above. The Hourly Operation Price can include:

(a) Verifiable labor, materials, fees, taxes, etc. that are only incurred when the unit operates; plus

(b) Payment for metered electricity consumed during the Settlement Interval. Compensation for electricity consumed shall be at a price per MWH equal to the Market Clearing Price for the interval and zone.

(2) Payment for Synchronous Condenser Operations shall be calculated in the following manner:

$$\mathbf{RunFee_{qi} = SUM(RunFee_{uiq})_u}$$

Where:

$$RunFee_{ui} = -1 * Running_{ui} * RunPr_u$$

(3) The formula below will be used to determine the total Synchronous Condenser Payments

to be allocated to each QSE in Section 6.9.4, Settlement Obligation for Black Start Service, RMR Standby Service, and RMR Synchronous Condenser Service.

$RunFee_{i} = SUM(RunFee_{qi})_{q}$

Where:

$RunFee_{uiq}$	Fee paid to Synchronous Condensers for each hour they run per interval per unit (for that QSE).
$RunPr_{u}$	Contractual Price Running $/Hour
$Running_{ui}$	Running = 1 if unit is synchronized with the grid during any part of the hour.
$RunFee_{qi}$	Fee paid to QSEs representing Synchronous Condensers per interval
$RunFee_{i}$	Summation of fees paid to QSEs representing Synchronous Condensers per interval for all QSEs in the Market

6.8.3.5 [Subsection currently not used]

6.8.3.6 Synchronous Condenser Start-Up Payment

There will be no compensation made for the start-up of a Synchronous Condenser Unit.

[PIP128: System design does not support compensation for SC Units]

$$\mathbf{SCU_{RMRiu} = -1 * StartPr_{u} * N_{iu}}$$

$$SCU_{RMRiq} = SUM(SCU_{RMRiu})_{q}$$

Where:

u	unit
i	Interval
q	QSE
N_{iu}	One (1) if a start is required by ERCOT in this interval. Zero otherwise.
SCU_{RMRiu}	RMR SC Startup Payment ($) for unit

SCU_{RMRiq}	RMR Startup Payment ($) for all units belonging to a QSE
$StartPr_u$	Contractual Amount for one start

6.8.3.7 RMR Excess Energy Rebates Outside of Contract Amounts

(1) If the RMR Unit generates energy in excess of the amount it is obligated to produce (i.e., the difference between the energy produced less the scheduled amount for any Settlement Interval is positive), the rebate of the excess amount produced will be based on the Owner's election of the Excess Energy Rebate Option in the RMR Agreement. The Excess Energy Rebate Options are based on the appropriate rebate to the Gross Revenue or Net Positive Margin, as follows:

Option (A): The net payment for energy above scheduled energy is based on the Market Clearing Price of Energy (MCPE) for the appropriate Settlement Interval and Congestion Zone (as described in Section 6.8.1.13), less an energy rebate, as described below. Currently the approved Gross Revenue-based energy rebate percentage is equal to ten percent (10%) of the Gross Revenue.

Option (B): The net payment for energy above scheduled energy is based on the MCPE (as described in Section 6.8.1.13), less an energy rebate of a percentage of the Net Positive Margin for energy. The Net Positive Margin for energy is the product of the positive difference between the Market Clearing Price for Energy (MCPE) and the RMR Energy Price times the amount of MWh delivered above the scheduled amount. Currently the approved Net Positive Margin-based energy rebate percentage is equal to ninety percent (90%) of the Net Positive Margin.

(2) Option (A): The rebate to ERCOT for RMR energy generated outside of the RMR Agreement terms under Option (A) above, shall be calculated in the following manner:

$$\mathbf{ER_{RMRiu} = [Max\ (0, (MR_{iu} - RS_{iu})) * MCPE_{iz} * GRRP]}$$

$$ER_{RMRiq} = SUM\ (ER_{RMRiu})_q$$

Where:

i	interval
u	unit
z	zone
ER_{RMRiu}	RMR Energy Rebate Amount for that interval for that unit
ER_{RMRiq}	RMR Energy Rebate Amount for that interval for that QSE
MR_{iu}:	Metered value for the Resource per interval for that unit using actual and/or estimated values.
RS_{iu}	Resource Scheduled quantity for that RMR Unit per interval
$MCPE_{iz}$	Market Clearing Price for Energy per interval in that zone

GRRP Approved Gross Revenue-based Rebate Percentage (currently 10%)

(3) Option (B): The rebate to ERCOT for RMR energy generated outside of the Agreement terms under Option (B) above, shall be calculated in the following manner:

$$\mathbf{ER_{RMRiu} = [Max\ (0, (MR_{iu} - RS_{iu})) * [Max\ (0, (MCPE_{iz} - RMR_{Eriu}))] * MRP]}$$

$$ER_{RMRiq} = SUM\ (ER_{RMRiu})_q$$

Where:

i	interval
u	unit
z	zone
ER_{RMRiu}	RMR Energy Rebate Amount for that interval for that unit
ER_{RMRiq}	RMR Energy Rebate Amount for that interval for that QSE
MR_{iu}:	Metered value for the Resource per interval for that unit using actual and/or estimated values.
RS_{iu}	Resource Scheduled quantity for that RMR Unit per interval
$MCPE_{iz}$	Market Clearing Price for Energy per interval in that zone
RMR_{Eriu}	RMR Energy Price per interval per unit
MRP	Approved Net Positive Margin-based Rebate Percentage (currently 90%)

(4) In accordance with Section 4.5.11.4, Receipt of QSEs Balancing Energy Bid Curves for RMR Unit, QSEs submitting Balancing Energy Service, bids using RMR Units, must keep the bids from RMR Units independent of other Balancing Energy Service bids.

6.8.3.8 RMR Non-performance for Unexcused Misconduct

(1) If a misconduct event is not excused, then to reflect this lower-than-expected quality of firmness, ERCOT charges the QSE that represents the RMR Unit an Unexcused Misconduct Amount as defined in the RMR Agreement for each RMR Unit.

$$\mathbf{UM_{RMRiu} = Fee * UMF}$$

$$UM_{RMRiq} = SUM(UM_{RMRiu})_q$$

Where:

i	interval to be calculated
u	unit
UM_{RMRui}	RMR Unexcused Misconduct event per unit for that interval
UM_{RMRiq}	RMR Unexcused Misconduct Fee for all units represented by that QSE in that interval
UMF	One if an Unexcused Misconduct Event occurred during that Operating Day otherwise zero.
Fee	Misconduct charge as specified in the RMR Agreement.

6.8.3.9 Synchronous Condenser Non-Performance for Unexcused Misconduct

(1) If a misconduct event is not excused, then to reflect this lower-than-expected quality of firmness, ERCOT charges the Entity an Unexcused Misconduct Amount as defined in the SCU Agreement for each SCU Unit.

$$\mathbf{UM_{SCUiu} = Fee * UMF}$$

$$UM_{SCUiq} = SUM(UM_{SCUiu})_q$$

Where:

i	interval to be calculated
u	unit
UM_{SCUui}	SCU Unexcused Misconduct event per unit for that interval
UM_{SCUiq}	SCU Unexcused Misconduct Fee for all units represented by that QSE in that interval
UMF	One if an Unexcused Misconduct Event occurred during that Operating Day otherwise zero.
Fee	Misconduct charge as specified in the SCU Agreement.

6.8.4 Capacity Payments for Voltage Support Provided to ERCOT

(1) Reactive Support: For Generation Resources required to provide VSS, Generation Entities will be required to maintain a voltage regulation schedule without compensation, limited to the quantity of Reactive Power the Generation Resources can produce at rated capability (MW), known as Unit Reactive Limit (URL). ERCOT may instruct Generation Resources to exceed their URL, without compensation, if reliability of the ERCOT System is at risk; and

(2) Power Reduction: Unit-specific Dispatch Instructions given to reduce real power in order to allow Voltage Support will be settled as OOME Down, specified in Section 6.8.2.3(5), Energy Payments, of these Protocols.

[PRR409; upon system implementation, replace Section 6.8.4 with the following.]

(1) **Uncompensated Reactive Support –** Generation Entities will be required to maintain a voltage regulation schedule without compensation limited to the quantity of Reactive Power the Generation Resource can produce at rated capability, (MW), and a power factor of 0.95 leading or lagging at rated MW output measured at the point of interconnection to the TSP.

(2) **Compensated Reactive Support –** If ERCOT instructs the Generation Resource to exceed a power factor of 0.95 leading or lagging at rated MW output measured at the point of interconnection to the TSP, and the Generation Resource provides additional Reactive Power, then ERCOT will pay for the additional Reactive Power provided at a

price that recognizes the avoided cost of reactive support Resources on the transmission network.

For the following equations, URL shall be that level of Reactive Power that results in a power factor of 0.95 leading or lagging at rated MW output measures at the unit main transformer high voltage terminals regardless of the type or age of the Resource. For Reactive Power deployments above Generation Site URL:

$$\mathbf{VARPAYAMT_{sqi} = -1*(VP*MVARINS_{sqi})}$$

Where:

$$MVARINS_{sqi} = \text{Max}\ \{0, (\text{Min}\ [VSOOM_{sqi}, MVAR_{sfi}] - MVAR_{S\ URLi})\}$$

And:

$$MVAR_{S\ URLi} = \text{Sum}\ (MVAR_{URLi})$$

Where:

$MVARINS_{sqi}$	Amount of instructed MVARh produced by a Generation Resource that are above the sum of the Unit's URLh during Settlement Interval i.
$MVAR_{sfi}$	Netted Metered Generation Resource Site Reactive Energy measured during the verbal deployment per interval.
$MVAR_{S\ URLi}$	Sum of all On-line Generation Resource URLh at the site per interval (MVARh).
$VSOOM_{sqi}$	Reactive Power Instructed Level per site per SQE per interval (MVARh).
$MVAR_{URLi}$	Generation Resource Unit specific leading or lagging URLh at the site per interval.
VP	$/MVARh price for instructed MVAR beyond a Generation Resource's site URL currently is $2.65/MVARh (based on $50.00/installed kVAR) with the exception of hydro Resources in the synchronous condenser mode.
$VARPAYAMT_{sqi}$	The amount of payment in dollars for each Generation Resource site in Settlement Interval I that is Dispatched beyond its URL.
$VARPAYAMT_{qi}$	The aggregated $VARPAYAMT_{sqi}$ in Settlement Interval i for each QSE.
$VARPAYAMT_{i}$	The aggregated $VARPAYAMT_{sqi}$ uplifted to the market in Settlement Interval i.

Note:

URL_u	The quantity of Reactive Power a Generation Resource can produce at rated capability, (MW), and a power factor of 0.95 leading or lagging measured at the unit main transformer high voltage terminals.

(3) Compensation for Power Reduction – Compensation for real power reduction to allow voltage support will be compensated as OOME Down, as specified in Section 6.8.2.3(5), Energy Payments, of these Protocols.

6.8.5 *Capacity Payments for Resources Supplied to ERCOT for Black Start Service*

(1) ERCOT will pay an hourly standby fee, determined through a competitive annual bidding process, with an adjustment for reliability based on a six (6) month rolling availability equal to eighty-five percent (85%) in accordance with the Black Start Agreement in Section 22, ERCOT Protocols Agreements.

(2) The calculation for Black Start is as follows:

$$\mathbf{PC_{BSui} = -1 * (BillPct_{ui} * BSCPu)}$$

$$PC_{BSqi} = -1 * SUM\ (BillPct_{ui} * BSCPu)_u$$

$$BillPct_{ui} = IF\ (HrRollEAF_{ui} >= .85,1,IF\ (HrRollEAF_{ui} > .35, - (1- ((.85- HrRollEAF_{ui}) * 2)), 0))$$

$$HrRollEAF_{ui} = ((\sum_{h=1\text{-}4380} AvailBlk_{ui}) / 4380)$$

$$AvailBlk_{ui} = Y$$

Where:

Y = 0 for unavailable service
Y = 1 for available service

Where:

i	interval
u	single Resource
$BSCP_u$	Black Start Contract Price of that single Resource
PC_{BSqi}	Procured Capacity Payment for Black Start Service per interval for the QSE
$BillPct_{ui}$	Reduced Percentage of payment due to less than eighty-five percent (85%) availability.
$HrRollEAF_{ui}$	Hourly Rolling Equivalent Availability Factor over a rolling six-month period.

$AvailBlk_{ui}$	Available of service

(3) The formula below is used to determine the total Black Start Payments to be allocated to each QSE in Section 6.9.4, Settlement Obligation for Black Start Service, RMR Standby Service, and RMR Synchronous Condenser Service.

$$\mathbf{PC_{BSi} = SUM\ (PC_{BSiq})_q}$$

$$PC_{BSqi} = SUM\ (PC_{BSiu})_q$$

Where:

i	interval
u	single Resource
$BSCP_u$	Black Start Contract Price of that single Resource
PC_{BSqi}	Procured Capacity Payment for Black Start Service per interval for the QSE
PC_{BSui}	Procured Capacity Payment for Black Start Service per interval per single Resource.
PC_{BSi}	Summation of fees paid to QSEs providing Black Start Service per interval for all QSEs in the market

Note: If less than 4380 hours have elapsed since the start date, HrRollEAF = 1.0

6.8.6 Capacity Payments for Emergency Interruptible Load Service (EILS)

(1) EILS capacity payments will be paid, for each EILS Contract Period, to QSEs representing EILS Resources in the following manner:

$$\mathbf{EIL_{qce(tp)} = -1 * BIDPrice_{qce(tp)} * BIDValue_{qce(tp)} * AvailFactor_{qce(tp)} * EILFactor_{qce(tp)} * TPh}$$

$$QSE\_EIL_{qc(tp)} = \sum EIL_{qce(tp)}$$

$$Total\_BIDValue_{qc(tp)} = \sum BIDValue_{qce(tp)}$$

Where:

q	QSE
c	Contract Period
e	Individual EILS Resource
tp	Hours in an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period
TPh	Number of hours in an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period

$AvailFactor_{qce(tp)}$	EILS availability factor for an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period, as calculated (and revised if necessary) in Section 6.10.13.3, Performance Criteria for EILS Resources
$BIDPrice_{qce(tp)}$	EILS Bid Price ($/MW) for each EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$BIDValue_{qce(tp)}$	Capacity (MW) for an EILS Resource contracted for EILS specific to an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$Total\_BIDValue_{qc(tp)}$	Total Capacity (MW) for an EILS Resource contracted for EILS specific to an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$EILFactor_{qce(tp)}$	EILS event performance factor for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period, as described in Section 6.10.13.3, Performance Criteria for EILS Resources
$EIL_{qce(tp)}$	EILS total payment for an EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$QSE\_EIL_{qc(tp)}$	EILS total payment to QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period

6.9 Settlement for ERCOT-Provided Ancillary Services

6.9.1 Settlement for ERCOT Ancillary Service Capacity Procured in the Day Ahead and Adjustment Periods

(1) ERCOT shall allocate to each QSE representing Load its portion of the total ERCOT requirement of each of the Ancillary Services of Regulation Up, Regulation Down, Responsive Reserve Service, and Non-Spinning Reserve Service. For settlement purposes, the QSE's total capacity allocation shall be based on the QSE's most recently calculated hourly Load Ratio Share for the applicable Operating Day.

(2) The QSE's settlement capacity shall be the QSE's total capacity allocation minus any self-arranged Resources scheduled.

(3) Each QSE's settlement charge (or imbalance), in dollars, for each Ancillary Service, by hour, shall be equal to the MCPC for the Ancillary Service (in dollars per megawatt), and multiplied by the QSE's settlement capacity (in megawatts).

(4) There is no difference in the manner in which costs for procurement in the Day Ahead and Adjustment Period are allocated for the following services:

(a) Regulation Up;

(b) Regulation Down;

(c) Responsive Reserve; and

(d) Non-Spinning Reserve.

6.9.1.1 Regulation Up Service Charge

(1) All costs of ERCOT procurement of Regulation Up shall be calculated as follows:

$$\mathbf{LA_{RUqi} = RUP_i * NTO_{RUqi}}$$

$$RUP_i = ((PC_{RUi} + PCI_{ESRUi}) * -1 / (COB_{RUti} - SA_{RUti}))$$

$$NTO_{RUqi} = (COB_{RUqi} - SA_{RUqi})$$

Where:

i	interval being calculated.
LA_{RUqi}	Regulation Up Service Capacity Load Allocation Charge ($) per interval for that QSE.
PC_{RUi}	Procured Regulation Up Capacity Costs ($) for the total Market.
PCI_{ESRUi}	Emergency Service Regulation Up Capacity Costs ($) for the total Market for the interval.
COB_{RUqi}	Obligated Regulation Up Capacity (MW) per interval of that QSE based on the QSE's most recently calculated hourly Load Ratio Share.
COB_{RUti}	Total Regulation Up Obligations Capacity (MW) in that interval.
SA_{RUti}	Total Self Arranged Regulation Reserve Up Capacity (MW) in that interval.
SA_{RUi}	Self Arranged Regulation Up Capacity (MW) Service per interval for that.
$QSERU_{pi}$	Regulation Up Price per interval.
RUP_i	Regulation Up Price per interval.
NTO_{RUqi}	Regulation Up Net Obligation (MW) per QSE per interval.

6.9.1.2 Regulation Down Service Charge

(1) All costs of ERCOT procurement of Regulation Down shall be calculated as follows:

$$\mathbf{LA_{RDqi} = RDP_i * NTO_{RDqi}}$$

$$RDP_i = ((PC_{RDi} + PCI_{ESRDi}) * -1 / (COB_{RDti} - SA_{RDti}))$$

$$NTO_{RDqi} = (COB_{RDqi} - SA_{RDqi})$$

Where:

i	interval being calculated

LA_{RDqi}	Regulation Down Service Charge per interval Regulation Down Reserve Capacity Load Allocation Charge ($) per interval for that QSE
PC_{RDi}	Procured Regulation Down Capacity Costs ($) for the total Market for the interval
PC_{ESRDi}	Emergency Service Regulation Down Capacity Costs ($) for the total Market for the interval
COB_{RDqi}	Obligated Regulation Down Capacity (MW) Service per interval of that QSE based on the QSE's most recently calculated hourly Load Ratio Share
SA_{RDqi}	Self Arranged Regulation Down Capacity (MW) Service per interval of that QSE
RD_{Pi}	Regulation Down Price per interval
NTO_{Rdqi}	Regulation Down Net Obligation (MW) per QSE per interval
COB_{RDti}	Total Regulation Down Obligations in that interval.
SA_{RDti}	Total Self Arranged Regulation Down in that interval

6.9.1.3 Responsive Reserve Service Charge

(1) All costs of ERCOT procurement of Responsive Reserve shall be calculated as follows:

$$\mathbf{LA_{RRqi} = RRP_i * NTO_{RRqi}}$$

$$RRP_i = (PC_{RRi} + PCI_{OOMRRi}) * -1 / (COB_{RRti} – SA_{RRti})$$

$$NTO_{RRqi} = (COB_{RRqi} - SA_{RRqi})$$

Where:

i:	interval being calculated
LA_{RRqi}	Responsive Reserve Capacity Load Allocation Service Charge ($) per interval for that QSE
PC_{RRi}	Procured Responsive Reserve Capacity Costs ($) for the total Market for the interval
PC_{OOMRRi}	Out of Merit Responsive Reserve Capacity Costs ($) for the total Market for the interval
COB_{RRqi}	Obligated Responsive Reserve Capacity (MW) Service per interval of that QSE based on the QSE's most recently calculated hourly Load Ratio Share
SA_{RRqi}	Self Arranged Responsive Reserve Capacity (MW) Service per interval of that QSE
RRP_i	Responsive Reserve Price per interval
NTO_{RRqi}	Responsive Reserve Net Obligation (MW) per QSE per interval
COB_{Rrti}	Total Responsive Reserve Obligations Capacity (MW) in that interval.
SA_{RRti}	Total Self Arranged Responsive Reserve Capacity (MW) in that interval

6.9.1.4 Non-Spinning Reserve Service Charge

(1) All costs of ERCOT procurement of Non-Spinning Reserve shall be calculated as follows:

$$\mathbf{LA_{NSqi} = NSP_i * NTO_{NSqi}}$$

$$NSP_i = ((PC_{NSi} + PCI_{OOMNSi}) * -1 \ / \ (COB_{NSti} - SA_{NSti}))$$

$$NTO_{NSqi} = (COB_{NSqi} - SA_{NSqi})$$

Where:

i	interval being calculated
LA_{NSqi}	Non-Spinning Reserve Capacity Load Allocation Charges ($) per interval for that QSE
PC_{NSi}	Procured Non-Spinning Reserve Capacity Costs ($) for the total Market for the interval
PC_{ESNSi}	Emergency Service Non-Spinning Reserve Capacity Costs ($) for the total Market for the interval
COB_{NSti}	Total Non-Spinning Reserve Obligations Capacity (MW) in that interval.
SA_{NSti}	Total Self Arranged Non-Spinning Reserve in that interval
COB_{NSqi}	Obligated Non-Spinning Reserve Capacity (MW) per interval of that QSE based on the QSE's most recently calculated hourly Load Ratio Share.
SA_{NSqi}	Self Arranged Non-Spinning Reserve Capacity (MW) per interval of that QSE
NS_{pi}	Non-Spinning Reserve price per interval
NTO_{NSqi}	Non-Spinning Reserve Net Obligation (MW) per QSE per interval

6.9.1.5 Settlement of ERCOT Ancillary Services Capacity Procured for Defaulted AS Obligations

(1) ERCOT shall allocate to each QSE, who has defaulted on their Ancillary Service Supply Obligation, their proportionate share of the cost of resolving the default. ERCOT shall assign default charges in the appropriate Adjustment Period. When a QSE defaults on a Supply Obligation, ERCOT will create a new Obligation for that service in which the QSE defaulted and assign that default Obligation to be equal in MW to the defaulted Supply Obligation.

(2) If ERCOT opens an Adjustment Period market for the sole reason of resolving a default condition, the QSE's that are awarded capacity in that Adjustment Period will be paid for their capacity as bid.

(3) The default Obligation cost will be allocated to those QSE's who have defaulted on their Obligation for the following Ancillary Services:

(a) Regulation Up;

(b) Regulation Down;

(c) Responsive Reserve; and

(d) Non-Spinning Reserve.

6.9.2 QSE Obligations for Capacity Services Obtained in the Adjustment Period

6.9.2.1 Settlement for RPRS

The Settlement for RPRS shall be as follows:

[PRR666 and PRR687: Replace Section 6.9.2.1 and insert new Section 6.9.2.1.1 (above), with the following upon system implementation:]

6.9.2.1 Settlement for RPRS Procured for System-wide Capacity Insufficiency

The Settlement for RPRS procured for system-wide capacity insufficiency, for each QSE, is as follows:

6.9.2.1.1 Replacement Reserve Under Scheduled Capacity

(1) The product of the maximum MCPC of Replacement Reserve procured for the hour, across all Congestion Zones (where the MCPC evaluated across all RPRS markets executed for the hour), multiplied by the QSE's maximum capacity insufficiency evaluated across all zones for each hour. A QSE's capacity insufficiency amount includes the maximum mismatch amount, evaluated across all zones for the hour. For the Operating Hour, a QSE's maximum capacity insufficiency, is the sum of (a) and (b) where (a) and (b) are as follows:

(a) The greater of zero (0) or the maximum interval sum of the difference, evaluated across the four (4) intervals in the hour, between a QSE's Adjusted Meter Load and the QSE's scheduled Load in each Settlement Interval for the Operating Hour at the time of procurement.

(b) The maximum mismatch amount that results from either (i) a mismatch in the QSE's Schedule as defined in Section 4.7.2, Schedule Validation Process, or (ii) a QSE selecting ERCOT as a Resource, at the time of procurement, evaluated over all applicable RPRS market snapshots for the hour for all Supply and Obligation mismatch combinations.

(2) When ERCOT procures Replacement Reserve Service to resolve system-wide capacity insufficiency, the calculation for Replacement Reserve Service Obligation for underscheduled capacity is:

$$US_{RP_{hq}} = Max_{Mh}(Max(MCPC_{RP_{hz}})) * Max_{Mh}\left[0,\left(Max\left(\sum_{z}\left(AML_{iq} - CL_{iq}\right)*4\right) + MMQ_{hq}\right)\right]$$

Where:

$$MMQ_{hq} = \sum_{Across\ q}\left\{\left(Max_{Mh}\left[\left(MMS_{hq}\right)\right]\right)\right\}$$

$$MMS_{hq} = Max_{i}\left(\sum_{q} Max\left(0,\left(QSSA_{TORP_i} - QOSB_{TORP_i}\right)\right) + \sum_{q} Min\left(0,\left(QSSB_{TORP_i} - QOSA_{TORP_i}\right)\right)\right)$$

Where:

h	Hour in trade day for which ERCOT purchased RPRS for capacity insufficiency
i	Hourly interval being evaluated, i=1, …4 where intervals 1, 2, 3, and 4 denote the set of 15-minute Settlement Intervals in a given hour
M	RPRS markets, in the event of multiple RPRS markets for a particular Operating Hour. This includes both the Day Ahead RPRS market all applicable RPRS markets executed during the Adjustment Period
q	QSE
z	Zone
AML_{iq}	Adjusted Metered Load (MWh) summed across all zones for a QSE, for Settlement Interval, i, of the settlement hour, h. This value includes estimated and/or actual meter values and the associated Transmission Losses & Distribution Losses and UFE.
CL_{iq}	QSE's Scheduled Load (MWh) by Settlement Interval, i, summed across all zones. (This quantity is evaluated across all snapshots of QSE's schedule for all RPRS markets for the particular hour)
$MCPC_{RPzh}$	Replacement Reserve Service Market Clearing Price of Capacity ($/MW), for the hour h, procured for system-wide insufficiency, over applicable markets, M, for the hour, per zone.
MMQ_{hq}	Maximum Mismatched net amount (MW), by hour , h, for the QSE. (This value is summed across all zones for all intervals in the hour and is evaluated across all applicable schedule snapshots.)
MMS_{hqi}	Mismatched Schedule Quantity (MW) representing either Inter-QSE Trades, or ERCOT scheduled as a Resource by settlement hour, h, by QSE, for each Replacement Reserve Market.
$QSSA_{TORP_i}$	QSE Supply Schedule for the buying QSE, A, by Settlement Interval, i, of the settlement hour, h, at the time of the Replacement Reserve Market.
$QOSA_{TORP_i}$	QSE Obligation Schedule for the selling QSE, A, by Settlement Interval, i, of the settlement hour, h, at the time of the Replacement Reserve Market.
$QOSB_{TORP_i}$	QSE Obligation Schedule for the selling QSE, B, by Settlement Interval, i,

	of the settlement hour, h, at the time of the Replacement Reserve Market.
$QSSB_{TORP_i}$	QSE Supply Schedule for the buying QSE, B, by Settlement Interval, i, of the settlement hour, h, at the time of the Replacement Reserve Market.
US_{RPhq}	Replacement Reserve Service Under Scheduled Charge ($) by hour for the QSE.

[PRR676: Replace Section 6.9.2.1 and insert new Section 6.9.2.1.1 (above), with the following upon system implementation:]

6.9.2.1 Settlement for Under Scheduled Capacity

The Settlement for Under Scheduled Capacity, for each QSE, is as follows:

6.9.2.1.1 Under Scheduled Capacity Charge

(1) The dollar amount charged to each QSE due to Under Scheduled Capacity for each Settlement Interval is the QSE's shortfall ratio share multiplied by the total OOMC and RPRS payments for the Settlement Interval, subject to a cap. The cap on the charge to each QSE is two multiplied by the total RPRS and OOMC payments for all QSEs multiplied by that QSE's Under Schedule Capacity, divided by the total capacity of RPRS and OOMC Resources procured during each Settlement Interval. For the Operating Hour, a QSE's maximum capacity insufficiency, is the sum of (a) and (b) where (a) and (b) are as follows,:

(a) The greater of zero (0) or the maximum interval sum of the difference, evaluated across the four (4) intervals in the hour, between a QSE's Adjusted Meter Load and the QSE's scheduled Load in each Settlement Interval for the Operating Hour at the time ERCOT initiates the process to procure RPRS.

(b) The maximum mismatch amount that results from either (i) a mismatch in the QSE's Schedule as defined in Section 4.7.2, Schedule Validation Process, or (ii) a QSE selecting ERCOT as a Resource, at the time ERCOT initiates the process to procure RPRS, evaluated over all applicable RPRS market snapshots for the hour for all Supply and Obligation mismatch combinations.

(2) The calculation of the Under Scheduled Capacity Charge shall be as follows:

$$USQ_{RP_{hq}} = Max_h \left[0, \left(Max_{iM} \left(\sum_z \left(AML_{iq} - CL_{iq} \right) * 4 \right) + MMQ_{hq} \right) \right]$$

Where:

$$MMQ_{hq} = \sum_{Across\ q} \left\{ \left(Max_{Mh} \left[\left(MMS_{hq} \right) \right] \right) \right\}$$

and

$$MMS_{hq} = Max_i \left(\sum_q Max\left(0, \left(QSSA_{TORPi} - QOSB_{TORPi}\right)\right) + \sum_q Min\left(0, \left(QSSB_{TORPi} - QOSA_{TORPi}\right)\right) \right)$$

$US_{RPhq} = Min\{2 * USQ_{RPhq} * (PC_{OOMRPhq} + LPC_{RPhq} + PC_{RPhq}) / Cap_{OOMRPhq}, [(PC_{OOMRPhq} + LPC_{RPhq} + PC_{RPhq}) * USQ_{RPhq}] / [\Sigma (USQ_{RPhq})]\}$

Where:

h	Hour in trade day for which ERCOT purchased capacity
i	Hourly interval being evaluated, i=1, …4 where intervals 1, 2, 3, and 4 denote the set of 15-minute Settlement Intervals in a given hour
M	RPRS markets, in the event of multiple RPRS markets for a particular Operating Hour. This includes both the Day Ahead RPRS market all applicable RPRS markets executed during the Adjustment Period
q	QSE
z	Zone
AML_{iq}	Adjusted Metered Load (MWh) summed across all zones for a QSE, for Settlement Interval, i, of the settlement hour, h. This value includes estimated and/or actual meter values and the associated Transmission Losses & Distribution Losses and UFE.
CL_{iq}	QSE's Scheduled Load (MWh) by Settlement Interval, i, summed across all zones. (This quantity is evaluated across all snapshots of QSE's schedule for all RPRS markets for the particular hour)
MMQ_{iq}	Maximum Mismatched net amount (MW), by hour, h, for the QSE. (This value is summed across all zones for all intervals in the hour and is evaluated across all applicable schedule snapshots.)
MMS_{hq}	Mismatched Schedule Quantity (MW) representing either Inter-QSE Trades, or ERCOT scheduled as a Resource by settlement hour, h, by QSE for each Replacement Reserve Market.
$QSSA_{TORP_i}$	QSE Supply Schedule for the buying QSE, A, by Settlement Interval, i, of the settlement hour, h, at the time of the Replacement Reserve Market.
$QOSA_{TORP_i}$	QSE Obligation Schedule for the selling QSE, A, by Settlement Interval, i, of the settlement hour, h, at the time of the Replacement Reserve Market.
$QOSB_{TORP_i}$	QSE Obligation Schedule for the selling QSE, B, by Settlement Interval, i, of the settlement hour, h, at the time of the Replacement Reserve Market.
$QSSB_{TORP_i}$	QSE Supply Schedule for the buying QSE, B, by Settlement Interval, i, of the settlement hour, h, at the time of the Replacement Reserve Market.

US_{RPhq}	Under Scheduled Charge ($)by hour for the QSE.
USQ_{RPhq}	Under Scheduled Quantity (MW) for each QSE for each hour
$PC_{OOMRPhq}$	Sum of all OOMC payments ($/hr) across ERCOT
LPC_{RPhq}	Sum of all Local RPRS payments ($/hr) across ERCOT
PC_{RPhq}	Sum of all Zonal/Capacity Insufficiency RPRS payments ($/hr) across ERCOT
Cap_{OOMRPi}	Sum of all Capacity (HSL) (MW) procured for OOMC or RPRS for the hourly interval

6.9.2.1.1 Replacement Reserve Uplift Charge

(1) Prior to direct assignment of Zonal Congestion costs, the QSE's Obligation for Replacement Reserve procured for CSC Congestion will be recovered as part of the System Congestion Fund described in Section 7.3.3.1, System Congestion Fund.

(2) The calculation for Replacement Reserve Uplift Charge will be as follows:

$$\mathbf{UC_{RPiq} = -1 * (\Sigma\ (PC_{RPiq} + LPC_{RPiq})_q + TCRPAY_{RPi} + \Sigma\ (CSC_{RPiq})_{q,CSC}) * LRS_{qi}}$$

$$\mathbf{TCRPAY_{RPi} = -1 * (\Sigma(TCRcsc_i) * SP_{CSCi})_{CSC}}$$

Where:

i:	Interval being calculated
q:	QSE
z:	CSC zone being settled
$UC_{RPi:}$	Replacement Reserve Service Uplift Charge ($)
PC_{RPiQSE}	Service Cost ($) per interval for all QSEs of Procured Capacity of Replacement Reserve procured to resolve Zonal Congestion and Capacity Insufficiency per single Resource
LPC_{RPiQSE}	Service Cost ($) per interval for all QSEs of Procured Capacity of Replacement Reserve procured to resolve Local Congestion per single Resource
CSC_{RPiQSE}	Replacement Reserve Service CSC Impact Capacity Charge ($) per interval for all QSEs
LRS_{qi}	Load Ratio Share (Factor) (Adjusted Metered Load / Total System Load) per hourly interval of that QSE
$TCRPAY_{RPi}$	Payment to TCR Account Holders for RPRS market per hourly interval
$TCRcsc_i$	Total number of TCRs per CSC per hourly interval
SP_{CSCi}	Shadow Price of RPRS per CSC per hourly interval

[PRR676: Replace Section 6.9.2.1.1 (above), with the following upon system implementation:]

6.9.2.1.2 Replacement Reserve Uplift Charge

The calculation for Replacement Reserve Uplift Charge will be as follows:

$$\mathbf{UC_{RPiq} = -1 * (\Sigma\ (PC_{OOMRPiq} + PC_{RPiq} + LPC_{RPiq})_q + \Sigma\ (US_{RPiq}) + TCRPAY_{RPi} + \Sigma\ (CSC_{RPiq})_{q,CSC}) * LRS_{qi}}$$

$$\mathbf{TCRPAY_{RPi} = -1 * (\Sigma(TCRcsc_i) * SP_{CSCi})_{CSC}}$$

Where:

i	Interval being calculated
q	QSE
z	CSC zone being settled
UC_{RPi}	Replacement Reserve Service Uplift Charge ($/hr) by QSE
PC_{RPiq}	Service payment ($/hr) by QSEof Procured Capacity of Replacement Reserve procured to resolve Zonal Congestion and Capacity Insufficiency per single Resource
LPC_{RPiq}	Service payment ($/hr) by QSE of Procured Capacity of Replacement Reserve procured to resolve Local Congestion per single Resource
US_{RPiq}	Replacement Reserve Service Under Scheduled Charge ($) by hour by QSE.
CSC_{RPiq}	Replacement Reserve Service CSC Impact Capacity Charge ($) per interval by QSE
LRS_{qi}	Load Ratio Share (Factor) (Adjusted Metered Load / Total System Load) per hourly interval of that QSE
$TCRPAY_{RPi}$	Payment to TCR Account Holders for RPRS market per hourly interval
$TCRcsc_i$	Total number of TCRs per CSC per hourly interval
SP_{CSCi}	Shadow Price of RPRS per CSC per hourly interval
PC_{OOMRPi}	OOMC payments ($/hr) by QSE

6.9.3 Settlement Charge for VSS

As Generation Entities are not compensated for Voltage Support Service, as specified in Section 6.8.4, Payments for Voltage Support Provided to ERCOT, there is no payment by Load of VSS costs.

[PRR409; upon system implementation, replace Section 6.9.3 with the following.]

The cost of Voltage Support Service as specified in Section 6.8.4, Capacity Payments for Voltage Support Provided to ERCOT, will be charged to each QSE on a Load Ratio Share as follows:

$$LA_{VSSiq} = -1*(VARPAYAMT_j)*LRS_{iq}$$

6.9.4 Settlement Obligation for Black Start Service, RMR Standby Service, RMR Synchronous Condenser Service and Emergency Interruptible Load Service

A QSE's Obligation for Black Start Service, RMR Standby Service, and RMR Synchronous Condenser Service will be equal to the QSE’s quantity of energy consumed hourly divided by the sum of all QSE's energy consumed in that hour, multiplied by the total ERCOT hourly cost for each of the following: Black Start Service, RMR Standby Service, RMR Synchronous Condenser Service and EILS.

6.9.4.1 Settlement Obligations for Black Start Service

(1) Black Start Service Costs will be allocated on a Load Ratio Share per QSE in the following manner:

$$\mathbf{LA_{BSqi} = -1 * PC_{BSi} * LRS_{qi}}$$

Where:

i	interval, equal to one hour
PC_{BSi}	Procured Capacity ($) for Black Start per interval.
LRS_{qi}	Load Ratio Share for the QSE per interval
LA_{BSqi}	Black Start Load Charge per interval per QSE.

6.9.4.2 Settlement Obligations for RMR Service

(1) Reliability Must Run costs, separated by category and available to QSEs via data extract (i.e., Standby Price and energy dollar amounts) will be allocated on a Load Ratio Share per QSE in the following manner:

$$\mathbf{LA_{RMRiq} = -1 * \{(\Sigma\ (E_{RMRiq}) + \Sigma\ (SB_{RMRiq}) + \Sigma\ (UM_{RMRiq}) + \Sigma ER_{RMRiq}) + \Sigma(CRMR_{iq})\} * LRS_{iq}}$$

Where:

i	Intervalq QSE
LA_{RMRiq}	RMR Load Allocation for that interval of that QSE
E_{RMRiq}	RMR Energy Dollar Amount per interval of that QSE
SB_{RMRiq}	RMR Standby Price in that interval of the QSE
UM_{RMRiq}	RMR Unexcused Misconduct Fee in that interval of that QSE
LRS_{iq}	Load Share Ratio for that interval of the QSE
ER_{RMRiq}	RMR Energy Rebate Amount for that interval for that QSE
$CRMR_{iq}$	Payment in that interval to MRA Resources reflecting the equivalent hourly capacity payment* and the actual hourly energy payment to each QSE
*	The equivalent hourly capacity payment for each hour will be determined by dividing each capacity payment by the number of hours covered by the terms of such capacity payment for the term that includes the hour.

6.9.4.3 Settlement Obligations for Synchronous Condenser Service

As Synchronous Condenser Units are not compensated for Synchronous Condenser Service, there is no payment by Load of Synchronous Condenser costs.

[PIP128: No compensation for SC]

Synchronous Condenser Costs will be allocated on a Load Ratio Share per QSE in the following manner:

$$\mathbf{SCLA_{qi} = -1 * (\Sigma\ (SSB_{ui})_u + \Sigma\ (SCU_{RMRiu})_u + \Sigma\ (RunFee_{ui})_u) * LRS_{iq}}$$

Where:

$SCLA_{qi}$	Synchronous Condenser Load Allocation for that interval
SSB_{ui}	Synchronous Condenser Standby Fee
SCU_{RMRiu}	Start Up Fee
$RunFee_{ui}$	Running Fee
LRS_{iq}	Load Share Ratio for that interval

6.9.4.4 Settlement Obligation for Emergency Interruptible Load Service

(1) EILS costs for an EILS Contract Period will be allocated based on the Load Ratio Share (LRS) of each QSE during each EILS Time Period in the EILS Contract Period. A QSE's LRS for an EILS Time Period in an EILS Contract Period will be the QSE's total Load for the EILS Time Period in the EILS Contract Period divided by the total ERCOT Load in the EILS Time Period in the EILS Contract Period. For the first settlement of the EILS Contract Period as described in paragraph (1) of Section 9.5.5, Settlement of Emergency Interruptible Load Service, LRS will be calculated using the final Load for each Operating Day in the EILS Contract Period. Final Load will be calculated according to the timing specified in Section 9.2.4, Final Statements. For the resettlement of the EILS Contract Period as described in paragraph (2) of Section 9.5.5, LRS will be calculated using the True-Up Load for each Operating Day in the EILS Contract Period. True-Up Load will be calculated according to the timing specified in Section 9.2.6, True-Up Statement.

(2) If a QSE opts for EILS Self-Provision, the QSE's LRS for an EILS Time Period in an EILS Contract Period will be the QSE's total Load for the EILS Time Period in the EILS Contract Period, divided by the total ERCOT Load in the EILS Time Period in the EILS Contract Period. The QSE's LRS for an EILS Time Period in an EILS Contract Period is then compared to the amount of EILS Self-Provision by the QSE for an EILS Time Period in an EILS Contract Period.

(a) If the EILS Self-Provision amount is equal to the QSE's LRS for an EILS Time Period in an EILS Contract Period, the QSE's obligation is zero (0).

(b) If the EILS Self-Provision amount is greater than the QSE's LRS for an EILS Time Period in an EILS Contract Period, the QSE's obligation is zero (0).

(c) If the EILS Self-Provision amount is less than the QSE's LRS for an EILS Time Period in an EILS Contract Period, the QSE's obligation is the difference between the EILS Self-Provision amount and the QSE's LRS.

(3) ERCOT shall calculate each QSE's obligation as follows:

$$\mathbf{LAEIL_{qc(tp)} = EILP_{qc(tp)} * EILOF_{qc(tp)}}$$

Where:

$$\mathbf{EILP_{qc(tp)} = \sum(QSE\_EIL_{qc(tp)}) / \sum EILOF_{qc(tp)}}$$

$$\mathbf{EILOF_{qc(tp)} = Max[0, (EILO_{qc(tp)} - SP_{qc(tp)})]}$$

$$\mathbf{EILO_{qc(tp)} = LRS_{qc(tp)} * \ Total\_BIDValue_{qc(tp)}}$$

$$\mathbf{SP_{qc(tp)} = \sum_{in=1}^{n} [(SPC_{qce(tp)}) * AvailFactor_{qce(tp)} * EILFactor_{qce(tp)}]}$$

Where:

q	QSE
c	Contract Period
e	Individual EILS Resource
tp	Hours in an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
n	The number of EILS Resources the QSE is offering into the market
in	An index number used to identify a QSE's EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$EILO_{qc(tp)}$	EILS Net Obligation (MW) per QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$EILOF_{qc(tp)}$	Adjusted final EILS obligation (MW) for a QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$EILP_{qc(tp)}$	Weighted average price for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$SP_{qc(tp)}$	EILS capacity (MW) self-provided by the QSE through EILS Self-Provision for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period, adjusted by ERCOT if necessary pursuant to paragraph (d) of Section 6.10.13.3, Performance Criteria for EILS Resource
$Total\_BIDValue_{qc(tp)}$	Total EILS Capacity (MW) procured through competitive bids plus EILS Self-Provision for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$SPC_{qc(tp)}$	Committed MW of a self-provided EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for an EILS Resource for an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period, as calculated (and revised if necessary) in Section 6.10.13.3
$EILFactor_{qce(tp)}$	EILS event performance factor for an EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period, as described in Section 6.10.13.3
$QSE\_EIL_{qc(tp)}$	EILS total payments to QSEs for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$LRS_{qc(tp)}$	EILS Load Ratio Share for the QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$LAEIL_{qc(tp)}$	EILS charge for the QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period

6.9.5 Settlement Obligation for Balancing Energy Service

6.9.5.1 Balancing Energy Clearing Price

(1) A Market Clearing Price for Energy (MCPE) will be calculated for each Settlement Interval by Congestion Zone as a product of the mathematical optimization model. The MCPE will be used to pay or charge each QSE, for each Settlement Interval for Balancing Energy Service.

(2) In the event that 30-Minute Non-Spinning Reserve Service (30MNSRS) is deployed for an interval in accordance with Section 6.7.4, Deployment of Non-Spinning Reserve Service, the MCPE for each zone shall be established according to paragraph (1) of Section 6.8.1.12, Payments for Balancing Energy Provided from Ancillary Services During the Operating Period.

6.9.5.2 Settlement For Balancing Energy for Load Imbalances

(1) For each applicable Congestion Zone and each Settlement Interval, each QSE's charge or credit for Balancing Energy consumed or provided in the Congestion Zone during the Settlement Interval, shall equal the sum of: 1) the product of the Congestion Zone's MCPE and the QSE's Balancing Energy Obligation for that Congestion Zone for Resources; and 2) the product of the Congestion Zone's MCPE and the QSE's Balancing Energy Obligation for that Congestion Zone for Obligations.

(2) Each QSE's Resource Balancing Energy Obligation (in MWh) for each Resource for each Settlement Interval, for each Zone, shall be equal to the actual energy production of all Resources represented by the QSE during the Settlement Interval; minus the QSE's final Balanced Schedule of its Resources for that Congestion Zone less any Inter-QSE Trades scheduled as a Resource. This cost will be calculated as Resource Imbalance as indicated in Section 6.8.1.13, Resource Imbalance.

(3) Each QSE's Load Balancing Energy Obligation quantity for each Settlement Interval, for each Zone, shall be equal to the QSE's Adjusted Metered Load consumption of all CR Loads represented by the QSE, minus the QSE's scheduled Load Obligation (total Obligation less any Inter-QSE Trades scheduled as a Load Obligation) for that Congestion Zone. This Load Imbalance will be calculated as follows:

$$\mathbf{LI_{izq} = -1 * (SL_{izq} - AML_{izq}) * MCPE_{iz}}$$

$$LI_{iz} = SUM(LI_{izq})_q$$

Where:

i	interval being calculated
z	zone being settled
LI_{izq}	Load Imbalance ($) per interval per zone per QSE

SL_{izq}	Scheduled Load (MWh) per interval per zone per QSE (total Obligation – Inter-QSE Trades)
AML_{izq}	Adjusted Metered Load (MWh) per interval per zone per QSE, which will include estimated and/or actual values and the associated Transmission & Distribution Losses and UFE.
$MCPE_{iz}$	Market Clearing Price of Energy ($/MWh) per interval per zone

(4) The QSE will pay the following for Load Imbalance if the net amount is positive. If the net amount is negative, the QSE will receive payment from the ERCOT in accordance with the Visa settlement sign conventions.

(5) Load Imbalance does include scheduled Exports from a DC Tie.

(6) Each QSE's Adjusted Metered Load in a Congestion Zone during a Settlement Interval shall be adjusted for Unaccounted for Energy (UFE), Transmission Losses and Distribution Losses, as per Section 13, Transmission and Distribution Losses determined by ERCOT in accordance with Section 11, Data Acquisition and Aggregation.

6.9.6 Settlement for Capacity Payments for Balancing Energy Up Load

Capacity payments made for Balancing Up Loads deployments will be allocated on a Load Ratio Share per QSE by summing the payments made for Balancing Up Loads capacity in each interval and multiplying it by the Load Ratio Share for that interval of the given QSE. The charge allocation will be calculated as follows:

$$\mathbf{LA_{BULqi} = -1 * PC_{BULi} * LRS_{qi}}$$

Where:

i	interval
q:	QSE
PC_{BULi}	Sum of any paid capacity ($) for Balancing Energy Up on Loads per interval
LRS_{qi}	Load Ratio Share for the QSE per interval
LA_{BULCqi}	Balancing Energy Up capacity Load allocation charge per interval per QSE

6.9.7 Settlement Obligations for Premiums for Individual Resource Dispatch Payments

Premiums paid for managing Local Congestion will be shared by the QSE's Load Ratio Share for the hours during which the premiums were paid.

6.9.7.1 OOM Capacity Charge

(1) The cost of Replacement Capacity that is not assigned in the mathematical optimization process will be shared by all QSEs in relation to their Load Ratio Share of the total ERCOT Load for the interval. The OOM Replacement Capacity Load Allocation will be calculated as follows:

$$\mathbf{LA_{OOMRPqi} = -1 * PC_{OOMRPi} * LRS_{qi}}$$

Where:

i	interval
u	unit
z	zone
LA_{OOMqi}	OOM Replacement Capacity Load Allocation Charges ($) for that QSE in that interval
PC_{OOMRPi}	OOM Replacement Capacity Costs ($) for the total market for that interval
LRS_{qi}	Load Ratio Share (0-1) = (Adjusted Metered Load for that QSE per interval/ Total System Load per interval)

[PRR676: Delete Section 6.9.7.1 (above), upon system implementation].

6.9.7.2 OOM Energy Charge

(1) Out Of Merit (OOM) Energy Load and Zonal OOME Load will be allocated on a Load Ratio Share per QSE by taking the sum of OOME and Zonal OOME Costs of all zones in that interval and multiplying it by the Load Ratio Share for that interval of the given QSE. The OOM Energy Load Allocation will be calculated as follows:

$$\mathbf{ELA_{OOMiq} = -1 * \sum (E_{OOMUPiz} + E_{OOMDNiz})_z * LRS_{iq}}$$

Where:

i	interval
u	unit
z	zone
ELA_{OOMiq}	OOM Energy and Zonal OOME Charges per interval per QSE
LRS_{iq}	Load Ratio Share Factor (0-1) = (Adjusted Metered Load for that QSE per interval / Total System Load for that interval for that QSE $LRS_{iq} = AML_{iq} / AML_i$
$E_{OOMUPiz}$	Out of Merit Energy and Zonal OOME Up Payments per interval per zone
$E_{OOMDNiz}$	Out of Merit Energy Down and Zonal OOME Down Payments per interval per zone

6.9.8 Settlement for Mismatched Inter-QSE Energy Schedules

QSE's will be paid the MCPE multiplied by the mismatch amount delivered to ERCOT and will be charged the MCPE multiplied by the mismatch amount received from ERCOT.

The mismatch amount delivered to ERCOT for each QSE for each zone shall be any amount in the mismatched inter-QSE energy schedules submitted by the QSE as a Resource which exceeds the corresponding Inter-QSE energy schedule submitted by a QSE as a Load. The mismatch amount received from ERCOT for each QSE for each zone shall be any amount in the mismatched inter-QSE energy schedules submitted by the QSE as a Load which exceeds the corresponding Inter-QSE energy schedule submitted by a QSE as a Resource.

$$\mathbf{MISD_{iqz} = -1 * MISAMTD_{iqz} * MCPE_{iz}}$$

$$\mathbf{MISR_{iqz} = MISAMTR_{iqz} * MCPE_{iz}}$$

Where:

i	interval
q	QSE
z	zone
$MISD_{iqz}$	Mismatched schedule payment for the mismatched amount delivered to ERCOT, per interval, per QSE, and per zone.
$MISR_{iqz}$	Mismatched schedule charge for the mismatched amount received from ERCOT, per interval, per QSE, and per zone.
$MISAMTD_{iqz}$	Mismatched amount delivered to ERCOT due to mismatched schedule per interval, per QSE, and per zone.
$MISAMTR_{iqz}$	Mismatched amount received from ERCOT due to mismatched schedule per interval, per QSE, and per zone.
$MCPE_{iz}$	Market Clearing Price for Energy per interval, and per zone.

Also:

$$\mathbf{MISD_{iz} = \Sigma\ (MISD_{iqz})_q}$$

$$\mathbf{MISR_{iz} = \Sigma\ (MISR_{iqz})_q}$$

Where:

$MISD_{iz}$	Total mismatched schedule payments for the mismatched amounts delivered to ERCOT, per interval, and per zone.
$MISR_{iz}$	Total mismatched schedule charges for the mismatched amounts received from ERCOT, per interval, and per zone.

6.10 Ancillary Service Qualification, Testing and Performance Standards

6.10.1 Introduction

Qualified Scheduling Entities (QSEs) providing Ancillary Services shall meet qualification criteria and performance measures to operate satisfactorily with ERCOT. ERCOT shall develop an Ancillary Services qualification and testing program and Real Time Monitoring Program for all suppliers of Ancillary Services that is based on the key factors needed for reliability. These programs will be approved by ERCOT Technical Advisory Committee and will be included in the Operating Guides. These performance factors shall be measured as precisely and efficiently as possible. General capacity testing verifies a Generation Resources or Load acting as Resources and Net Dependable Capability. Qualification tests allow the potential provider's portfolio to demonstrate the minimum capabilities necessary to deploy an Ancillary Service, and performance measures assess the Real Time delivery of a service by an Ancillary Services provider.

All loads may be provisionally qualified for a period of ninety days as a Load acting as a Resource and may be eligible to participate as Resource. Loads that have installed the appropriate equipment with verifiable testing data may be provisionally qualified as a provider of Ancillary Services once the specific requirements for the Ancillary Services specified in the Operating Guides have been completed to ERCOT's reasonable satisfaction.

All loads may be provisionally qualified for a period of ninety (90) days to participate as a Balancing Up Load (BUL), provided the Load is metered with an IDR to ERCOT's reasonable satisfaction. Any Load may be qualified to participate as a BUL Resource, provided the Load meets the metering requirements (including any Sampling standards identified in Section 18, Load Profiling) established by ERCOT once the following ERCOT requirements have been met:

- ESI-ID registration of BUL by the QSE;
- Telemetered BUL response value is installed and tested between QSE and ERCOT; and
- For Dynamic Obligation Schedule (DSBUL), telemetered dynamic Obligation telemetry tested between QSE and ERCOT.

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

6.10.2 General Capacity Testing Requirements

Within the first fifteen (15) days of each Season, each QSE shall provide ERCOT a seasonal High Sustainable Limit (HSL) for any Generation Resource with a capacity greater than ten (10) 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 shall take into account auxiliary Load and gross and net real power capability of the Generation Resource. Each QSE shall update its Resource Plan 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.

To verify that the HSL reported in the Resource Plan 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 to the QSE to operate the designated Generation Resource at its HSL as shown in the QSE's Resource Plan at the time the test is initiated. 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 Low Sustainable Limit (LSL) when ERCOT sends the verbal Dispatch Instruction to begin the test, the QSE shall have up to sixty (60) minutes to allow the Resource to reach ninety percent (90%) of its HSL and up to an additional twenty (20) minutes for the Resource to reach the HSL shown in the Resource Plan 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 fifty percent (50%) of its HSL when ERCOT begins the test, the QSE shall have sixty (60) minutes for the Resource to reach its HSL. If the Resource is operating at or above fifty percent (50%) of its HSL when ERCOT begins the test, the QSE shall have thirty (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 thirty (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 thirty (30) minutes of constant output. After each test, QSEs will complete and submit an updated test form that ERCOT shall provide.

ERCOT may test multiple Generation Resources within a single QSE within a single twenty-four (24) hour period. However, in no case, shall ERCOT test more than two (2) Generation Resources within one (1) QSE simultaneously. All Resources On-line in an Aggregated Unit will be measured on an aggregate capacity basis. All QSEs associated with a jointly owned unit will be tested simultaneously. Hydro and wind 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.

Should the designated Generation Resource fail to reach its HSL as posted in its Resource Plan 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 at a time determined by ERCOT and may retest as many times as desired. Subject to ERCOT approval, the requested retest will take place within the first twenty-four (24) Operating Hours of the designated Generation Resource after the request for retest or three (3) Business Days after the request for retest. Any verbal Dispatch Instruction ERCOT issues as a result of a QSE-requested retest will not be compensated under Section 6.8.2.3, Energy Payments, but will be considered as an instructed deviation for compliance purposes.

A Resource Entity owning a hydro unit operating in the synchronous condenser fast response mode to provide hydro Responsive Reserve shall evaluate the maximum capability of the Resource each Season.

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 Technical Advisory Committee (TAC) subcommittee. ERCOT shall report monthly 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 in the Resource Plan, the percentage that failed to meet their HSL reported in the Resource Plan and the total MW capacity shortfall of those Resources that failed to meet their HSL reported in the Resource Plan.

ERCOT shall conduct all unannounced Generation Resource testing by using Out of Merit Energy (OOME) Dispatch Instructions to the Generation Resource under test. Any verbal Dispatch Instruction ERCOT issues as a result of a QSE-requested retest will not be compensated under Section 6.8.2.3 but will be considered as an instructed deviation for compliance purposes.

Load acting as a Resource (LaaR) to provide Ancillary Services shall have its telemetry attributes verified by ERCOT annually. In addition, once every two (2) years, any LaaR providing Responsive Reserve Service (RRS) shall test the under frequency relay or the output from the solid-state switch, whichever applies, for correct operation. However, if the Load'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/or the biennial relay testing requirement.

Specific Loads to be used for the first time as a Resource to provide Responsive Reserve, Non-Spinning Reserve or Replacement Reserve must be correctly evaluated prior to their provisional qualification to provide Ancillary Services. During the provisional qualification period, ERCOT shall conduct a qualification test of each LaaR consisting of an actual Load interruption. If a LaaR passes the qualification test during the provisional qualification period, ERCOT shall consider the LaaR qualified to provide Responsive Reserve, Non-Spinning Reserve or Replacement Reserve. ERCOT shall develop a standard test procedure for the qualification test required under this subsection.

QSEs shall be responsible for qualifying any Load desiring to have the QSE represent it to provide BUL Service.

[PRR484: Add the following sentence to the end of the above paragraph ("QSEs shall be responsible for qualifying…BUL Service. ") upon system implementation:]

Loads controlled under a qualified Direct Load Control (DLC) program may be qualified as a group.

The QSE shall nominate to ERCOT, at least annually, that it is representing an amount of BUL for which it wishes to be qualified to provide. At a time selected by ERCOT, the ERCOT operator will notify the QSE that it wants to verify the QSE's ability to provide ERCOT with the appropriate signal simulating that it has initiated an ERCOT requested BUL reduction. The QSE Operator will immediately simulate the initiation of the reduction and provide ERCOT with the appropriate signal representing some amount of Load to be qualified to provide BUL Resources. Once ERCOT has verified that it has received an appropriate Load reduction signal from the QSE and has successfully completed the BUL registration process, the QSE will be qualified to provide BUL Resources. Any changes to the BUL portfolio will require subsequent updates to the registration process. For Non Opt-In Entities (NOIEs) representing specific Loads qualified as BULs that are located behind the NOIE Settlement Meter points, the NOIE shall provide an alternative unique descriptor of the qualified BUL Load for ERCOT's records.

Generation Resources and Loads acting as Resources shall be evaluated at least annually by ERCOT for:

(1) Correct operation of telemetry of the breakers controlling the Resource;

(2) Correct mapping of QSE-provided telemetry of Ancillary Service energy to the appropriate energy Settlement Meter;

(3) Data rate update requirements; and

(4) Any other required telemetry attributes.

In addition, a LaaR that is used to provide RRS will be subject to an actual interruption test at a date and time determined by ERCOT and known only to ERCOT and the affected TDSP, at least once in every three hundred and sixty five (365) day period to verify ability to respond to an ERCOT Dispatch Instruction. To successfully pass this test, the LaaR must deploy at least ninety-five percent (95%) of its scheduled Load within ten (10) minutes of the receipt of the ERCOT Dispatch Instruction by the LaaR's QSE. If a LaaR has responded to an actual ERCOT Dispatch Instruction with at least a ninety-five percent (95%) reduction in its Load within ten (10) minutes in the applicable calendar year, ERCOT will use that response in lieu of another actual interruption test. QSEs may request to have individual LaaRs aggregated for the purposes of actual interruption tests. All performance evaluations will apply on an individual Resource basis.

All Generation Resources and LaaRs shall meet all requirements specified in the Operating Guides for proper response to system frequency. ERCOT may reduce the amount a Resource may contribute toward Ancillary Services if it finds unsatisfactory performance of the Resource as defined in these Protocols and the Operating Guides.

Qualification of a Resource, including a LaaRor an Emergency Interruptible Load Service (EILS) Resource, shall remain valid for such 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.

6.10.3 Ancillary Services Qualification Criteria and Portfolio Test Methods

Only QSEs that have been qualified and tested may be used to provide Ancillary Services. ERCOT shall develop and operate its qualification and testing program to meet the following requirements for each Ancillary Service.

ERCOT may grant a "Provisional Qualification," for a period not to exceed forty-five (45) days, to QSEs that are required to be, but have not yet been tested. For all Ancillary Service testing, QSEs must utilize Resources that are to be used by the QSE to provide the Ancillary Services to be tested. Notwithstanding the failure of a QSE with Provisional Qualification to meet the applicable Ancillary Service criteria, such QSE may provide such Ancillary Service to the extent permitted by the terms of the Provisional Qualification.

A QSE shall be qualified and tested to provide Service prior to initial operation and every five years thereafter.

A QSE may request a test for re-qualification at any time, but no later than the expiration of its current Ancillary Service qualification, and no more frequently than once every twelve (12) months. At the time of a request by a QSE for re-qualification, ERCOT may approve the re-qualification based on the AS performance metrics using the following criteria:

(1) For Balancing Energy and RGS, the QSE's SCE Monitoring Criteria performance scores in Section 6.10.5.3, SCE Monitoring Criteria, were passing for five (5) out of the previous six (6) months.

(2) For RRS, the RRS criteria in Section 6.10.5.4, Responsive Reserve Service Deployment Performance Monitoring Criteria, were passing for five (5) out of the previous six (6) performance intervals.

(3) For NSRS, the NSRS monitoring criteria in Section 6.10.5.5, Non-Spinning Reserve Service Deployment Performance Monitoring Criteria, were passing for five (5) out of the previous six (6) deployment measurements without retest.

If the QSE passes the criteria, the QSE will be exempt from re-qualification testing for five (5) years from the date of the exemption request. ERCOT shall provide monthly performance updates to the QSE for the above criteria.

ERCOT is authorized to call up to two unannounced, unscheduled qualification tests after presenting to the QSE supporting information of an indication that a Resource may not be able to meet its stated Net Dependable Capability during any calendar year.

QSEs may qualify by using either Generation Resource(s) or Load(s) Acting as a Resource (LaaR(s)). If a QSE qualifies by using only a LaaR then the QSE may only provide Ancillary Services using LaaRs and will not be qualified to provide Ancillary Services using Generation Resources. However, if a QSE successfully completes the qualification using Generation Resource(s), that QSE will be qualified to provide Ancillary Services from both Generation Resources and LaaRs.

ERCOT may grant a "Provisional Qualification," for a period not to exceed ninety (90) days, to a QSE that has performed an Ancillary Service qualification test (or tests) in good faith but failed to qualify due to problems that, in the sole discretion of ERCOT, are determined to be non-critical for the purpose of providing one or more Ancillary Services. Notwithstanding the failure of a QSE with Provisional Qualification to meet the applicable Ancillary Service criteria, such QSE may provide such Ancillary Service to the extent permitted by the terms of the Provisional Qualification.

6.10.3.1 Regulation

(1) A regulation qualification test is conducted during a continuous sixty (60) minute period agreed on in advance by the QSE and ERCOT. QSEs may be qualified to provide Regulation Up or Regulation Down, or both, in separate testing.

(2) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice communication circuits in order to validate the voice circuits.

(3) For the sixty (60) minute duration of the test, when market and reliability conditions allow, the ERCOT Control Area Operator shall send a random sequence of raise, hold, and lower control signals to the QSE, To facilitate accurate measurements, each signal (raise, lower, or hold) shall remain unchanged for at least two (2) minutes. The control signals shall not request QSE portfolio performance beyond the stated high limit, low limit, and ramp rate limit agreed on prior to the test. During the test, one ten (10) minute period will test the QSE's ability to achieve the entire amount of Regulation Up requested for qualification during the period. One ten (10) minute period will test the QSE's ability to achieve the entire amount of Regulation Down requested for qualification during the period. To facilitate testing of large portfolios, ERCOT may test maximum ramp capability on subsets of Generation Resources in a portfolio.

(4) The QSE's portfolio average real power output for each clock minute will be measured and recorded. The regulation test shall be conducted when all other schedules are held constant so that any real power increase or decrease is the result of the regulation requirement. The correlation coefficient between the expected average power from one minute to the next [limited to no more than the initial value + (request ´ 1/2 ´ stated ramp rate)], and the actual measured real power output during those minutes shall be statistically significant to two (2) positive standard deviations in order to pass the test.

(5) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing RGRS and shall provide a copy of the certificate to the QSE.

6.10.3.2 Responsive Reserve Qualification Testing Criteria

(1) Testing using Generation Resource(s)

(a) A test for RRS shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(c) At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the QSE, ERCOT shall send a signal to the QSE requesting it to provide an amount of RRS. The QSE shall acknowledge the start of the test.

(d) For the thirty (30) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for ten (10) minutes; and (iii) for each of the subsequent nineteen (19) clock-minutes. All measurements shall confirm the additional delivery of energy due to the deployment of RRS in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT. Satisfactory performance shall be deemed acceptable if ninety percent (90%) of each clock-minute measurement ten (10) minutes after notice through the balance of the test period is equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount expected.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing RRS and shall provide a copy of the certificate to the QSE.

(2) Testing using LaaR(s)

(a) A test for RRS shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(c) At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the QSE, ERCOT shall send a signal to the QSE requesting it to provide an amount of RRS. The QSE shall acknowledge the start of the test.

(d) Upon ERCOT issuing a verbal instruction to the QSE to deploy the LaaR, the QSE shall demonstrate that it has procedures in place to satisfy a satisfactory deployment of the LaaR(s) providing RRS as required in EEA Level 2A, Section 5.6.7, EEA Levels. All measurements shall confirm the additional delivery of energy due to the deployment of RRS in an amount equal to at least ninety-five percent (95%) and no more than one hundred and fifty percent (150%) of the amount requested by ERCOT. A deployment will be deemed acceptable when ERCOT confirms the interruption of the Load(s) within ten (10) minutes of issuance of the instruction by ERCOT.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing RRS from LaaRs and shall provide a copy of the certificate to the QSE designating its qualification to provide RRS from LaaRs.

6.10.3.3 Non-Spinning Reserve Qualification Testing Criteria

(1) Testing using Generation Resource(s)

(a) A test for Non-Spinning Reserve Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(c) 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 using ERCOT's Messaging System requesting it to provide an amount of Non-Spinning Reserve the QSE wishes to be qualified to. The QSE shall acknowledge the start of the test.

(d) For the sixty (60) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for thirty (30) minutes; and (iii) for each of the subsequent twenty-nine (29) clock minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Non-Spinning Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT.

(e) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing Non-Spinning Reserve and shall provide a copy of the certificate to the QSE.

(2) Testing using Load(s) Acting as a Resource

(a) A test for Non-Spinning Reserve Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(c) 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 using ERCOT's Messaging System requesting the QSE provide the amount of Non-Spinning Reserve the QSE wishes to be qualified to provide. The QSE shall acknowledge the start of the test.

(d) Upon ERCOT issuing a verbal instruction to QSE to deploy the LaaR, the QSE shall demonstrate that it has procedures in place to satisfactorily deploy LaaR(s) providing Non-Spinning Reserve Service. All measurements shall confirm the additional delivery of energy due to the deployment of Non-Spinning Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred and fifty percent (150%) of the amount requested by ERCOT. A deployment will be deemed acceptable when ERCOT confirms the interruption of the Load(s) within thirty (30) minutes of issuance of the instruction by ERCOT.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing Non-Spinning Reserve from LaaRs and shall provide a copy of the certificate to the QSE designating its qualification to provide Non-Spinning Reserve from LaaRs.

6.10.3.4 Balancing Energy

(1) Testing using Generation Resource(s)

(a) A test for Balancing Energy Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(c) 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 using ERCOT's Messaging System requesting it to provide an amount of Balancing Energy. The QSE shall acknowledge the start of the test. During the sixty (60) minute duration of the test, within the limits of requested qualification, ERCOT will vary the amount of Balancing Energy requested.

(d) A QSE may qualify to provide only Balancing Energy Down Service using only Uncontrollable Renewable Resources by providing Balancing Energy Down Service, within the limits of requested qualification, in an amount available from the Uncontrollable Renewable Resource's Resource Plan at the time of the Dispatch Instruction. All measurements shall confirm the reduced delivery of energy due to the deployment of Balancing Down Energy Service when the generation amount of the Uncontrollable Renewable Resource is less than or equal to the Uncontrollable Renewable Resource's Resource Plan, less the amount requested by ERCOT.

(e) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing Balancing Energy and shall provide a copy of the certificate to the QSE.

(2) Testing using Load(s) Acting as a Resource

(a) A test for Balancing Energy Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(c) 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 using ERCOT's Messaging System requesting it to provide an amount of Balancing Energy. The QSE shall acknowledge the start of the test.

(d) Upon ERCOT issuing a verbal instruction to QSE to deploy the LaaR, the QSE shall demonstrate that it has procedures in place to satisfactorily deploy LaaR(s) providing Balancing Up Energy Service. All measurements shall confirm the additional delivery of energy due to the deployment of Balancing Up Energy Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred and fifty percent (150%) of the amount requested by ERCOT. A deployment will be deemed acceptable when ERCOT confirms the interruption of the Load(s) within ten (10) minutes of issuance of the instruction by ERCOT.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing Balancing Energy from LaaRs and shall provide a copy of the certificate to the QSE designating its qualification to provide Balancing Energy from LaaRs.

6.10.3.5 Reactive Supply from Generation Resources required to provide VSS

(1) The Generation Entity must verify and maintain its stated Reactive Power capability for each of its Generation Resources required to provide VSS, as required by the Operating Guides. Generation Resources required to provide VSS reactive capability limits shall be specified considering nominal substation voltage.

(2) The Generation Entity will 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 will be performed on initial qualification and at a minimum of once every two years ERCOT may require additional testing if it has information indicating that current data is inaccurate. The Generation Entity is not obligated to place Generation Resources required to provide VSS On-line solely for testing. The reactive capability tests are run at a time agreed on in advance by the Generation Entity, its QSE, the applicable TDSP, and ERCOT.

(3) Maximum lagging power factor reactive operating limit shall be demonstrated during peak Load Season, at or above ninety-five percent (95%) of the most currently tested net dependable megawatt capability, insofar as system voltage conditions and other factors will allow. The Generation Resource required to provide VSS should be required to maintain this level of Reactive Power for at least fifteen (15) minutes.

(4) Maximum leading power factor reactive operating limit shall be demonstrated during light Load conditions, with the unit operating at a typical output for that condition, insofar as system voltage conditions and other factors will allow. The unit should be required to maintain this level of Reactive Power for at least fifteen (15) minutes.

(5) The Generation Entity shall perform the unit Automatic Voltage Regulator (AVR) tests and shall supply AVR data as specified in the Operating Guides. The AVR tests will be performed on initial qualification and periodically at an ERCOT-set interval no more often than once every five (5) years. The AVR tests are run at a time agreed on in advance by the Generation Entity, its QSE, the applicable TDSP, and ERCOT.

6.10.3.6 System Black Start Capability

(1) Qualification will be provided to any Black Start Resource that 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) If not starting itself, has an ERCOT approved firm standby power contract with deliverability under ERCOT blackout circumstances from another power pool that can be finalized upon selection as a Black Start Resource;

(h) If not starting itself, has an ERCOT approved agreement with the necessary TDSPs for access to another power pool, for coordination of switching during a Black Start event, for coordination of maintenance through the ERCOT Outage scheduler for all non-redundant transmission startup feeds; and

(i) If dependent upon non-ERCOT transmission Resources, agreements providing this Transmission Service have been provided in the proposal.

(2) On successful demonstration of system Black Start Service capability, ERCOT shall qualify the Black Start Resource as being permitted to provide the system Black Start Service capacity and shall provide a copy of the certificate to 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 Black Start Service must be completed by December 1 of each year. ERCOT shall revoke the qualification of a Black Start Resource and reduce the Black Start

Resources' hourly standby fee (if under an existing Black Start Agreement) to zero (0) during the time of disqualification if the Black Start Resource fails to perform successfully during a test describe herein, until the Black Start Resource is successfully retested. ERCOT may limit the number of retests allowed. Retesting is only required for the aspect of system Black Start Service 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 (2) 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 A, Standard Form Black Start Agreement. The following tests are required for Black Start Service qualification:

(a) Basic Starting Test:

(i) The basic ability of the Black Start Resource to start itself, or start from a normally open interconnection to another power pool, without support from the ERCOT System, is tested annually, either as a stand-alone test or with the other tests described below. The test is run during a one (1) week period agreed on 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;

(ii) ERCOT shall confirm the dates of the test with the Black Start Resource;

(iii) At a time during a previously agreed test week window not previously disclosed to the Black Start Resource, ERCOT will initiate the test;

(iv) The Black Start Resource, including all auxiliary Loads, will be isolated from the ERCOT power system, except for the transmission that connects the Resource to another power pool if the startup power is supplied by a firm standby contract. Black Start Resources starting with the assistance of another power pool through a firm standby agreement will connect to the external grid, start-up, carry internal Load, disconnect from the external grid if not supplied through a black start capable Direct Current (DC) Tie, and continue equivalently to what is required of other Black Start units;

(v) The Black Start Resource will start without assistance from the ERCOT System, except for the transmission that connects the Resource to another power pool if the startup power is supplied by a firm standby contract;

(vi) The Black Start Resource must remain stable (in both frequency and voltage) in no Load condition or while supplying only its own auxiliary Loads or Loads in the immediate area for at least thirty (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 unit within the required reactive range. Data to verify these settings will be provided to ERCOT; and

(viii) Qualification under the Basic Starting Test is valid for one (1) year.

(b) Line-Energizing Test:

(i) The ability of the Black Start Resource to energize transmission will be tested when conditions permit as determined by the TDSP but at least once every three years. Tests will be conducted at a time agreed on by the Black Start Resource, TDSP, and ERCOT;

(ii) Sufficient transmission will be de-energized such that when it is 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 calls for 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) The Resource Entity controlling the Black Start Resource shall coordinate with TDSPs to submit necessary transmission outages to ERCOT for approval thirty (30) days before the scheduled test date;

(iv) The test shall commence with a Basic Starting Test;

(v) ERCOT will direct the Black Start Resource to energize the previously de-energized transmission, while monitoring frequency and voltages at both ends of the line. Alternatively, if ERCOT agrees, the transmission line can be connected to the Black Start Resource before starting, allowing the Resource to energize the line as it comes up to speed;

(vi) The Black Start Resource must remain stable (in both frequency and voltage) in no Load condition or while supplying only its own auxiliary Loads or external Loads and controlling voltage for at least thirty (30) minutes;

(vii) This test may be performed together with the Basic Starting Test in one thirty (30) minute interval; and

(viii) Qualification under the Line-Energizing Test is valid for three (3) years.

(c) Load-Carrying Test:

(i) The ability of the Black Start Resource to remain stable and to control voltage and frequency while supplying restoration power to the Load that ERCOT's restoration plan calls for the Black Start Resource to supply shall be tested as conditions permit, but at least once every five (5) years;

(ii) The test shall commence with a Basic Starting Test followed by a Line-Energizing Test;

(iii) The TDSP operator will direct picking up sufficient Load to demonstrate the Black Start Resource's capability to supply the required power identified in ERCOT's restoration plan, while maintaining voltage and frequency for at least thirty (30) minutes. In the event that there is no additional Load in the immediate vicinity of the plant (*e.g.*, hydro plants), this test can be conducted with no Load;

(iv) This test may be performed together with the Basic Starting Test and Line Energizing Test in one thirty (30) minute interval; and

(v) Qualification under the Load-Carrying Test is valid for five (5) 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;

(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 staff 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.

Potential Black Start Service bidders may request next start unit information from ERCOT prior to the selection process to satisfy this requirement. ERCOT shall request this information from the designated next start unit as follows: ERCOT may require any Generation Resource to provide largest motor startup information and unit startup energy requirements as needed to validate Black Start proposals or plans submitted by other Generation Resources. Such data, if requested by ERCOT, shall be provided by the QSE representing the Generation Resource or the Generation Resource Entity to ERCOT within thirty (30) days. Such information shall be considered Protected Information by the requesting Resource Entity when provided to the Resource Entity;

(iii) This test shall be repeated when a new next start unit is selected;

(iv) If a physical test is performed, the test shall commence with a Basic Starting Test, followed by a Line-Energizing Test 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 thirty (30) minutes;

(vi) If a physical test is performed, this test may be performed together with the Basic Starting Test, Line-Energizing Test, and Load-Carrying Test in one thirty (30) minute interval; and

(vii) Qualification under the Next Start Resource Test is valid until a new next start unit is selected.

(3) ERCOT shall decertify a Black Start Resource for the calendar year as described in "Section 7. Black Start Decertification" of Section 22, Attachment A, Standard Form Black Start Agreement if the Black Start Resource fails to perform successfully during an actual ERCOT System black out event and the Black Start Resource has been declared available, as defined in "Section 9(B)(1)" of Section 22, Attachment A, Standard Form Black Start Agreement.

6.10.4 Ancillary Service Deployment Performance Measures

ERCOT shall measure the performance of QSEs according to the following requirements. ERCOT shall identify those QSEs that continually perform at a less-than-satisfactory level and shall pursue compliance mechanisms for QSEs as specified in the NERC Reliability Compliance Program and as may be further specified in the Protocols and Operating Guides.

6.10.4.1 Performance Measurement Standard

The expected amount of energy resulting from the deployment instructions of ERCOT is represented as a real power schedule of instructed Ancillary Services from the QSE. This schedule, subject to the agreed-on QSE capabilities, is the requested Ancillary Service output of the QSE Resources. Considering that the QSE may be operating a portfolio and has scheduled a base energy quantity for each Settlement Interval, the total QSE schedule is the amount of power from the base Resource schedule plus any such instructed Ancillary Services. The performance of a QSE can be measured by the difference between the actual and expected (requested) Resource output of the QSE. The ERCOT Ancillary Services that result in the deployment of real power applies in the measurement of Real Time provision of the reliability product are (1) Regulation Service, (2) Responsive Reserve Service, (3) Non-Spinning Reserve Service, and (4) Balancing Energy Service. These services combined form ERCOT Reliability Ancillary Services.

Performance measures for the remaining Ancillary Services, Replacement Reserves, Reactive Power Supply from Generation and System Black Start are treated separately.

6.10.4.2 Base Power Schedule Calculation.

For performance measurement purposes, ERCOT shall calculate for each QSE every two (2) seconds the expected power resulting from the QSE's Resource schedule less any other QSEs scheduled as a Resource. The expected power function will be calculated such that schedule changes between Settlement Intervals will be ramped during a ten (10) minute fixed ramp period starting five (5) minutes prior to the start of a Settlement Interval. ERCOT will consider energy provided outside of the Resource schedule in the Settlement Interval as a result of ramping an instructed deviation.

[PRR601, PRR803: Replace the paragraph above with the following upon system implementation:]

For performance measurement purposes, ERCOT shall calculate for each QSE every two (2) seconds the expected power resulting from the QSE's Resource schedule less any other QSEs scheduled as a Resource. The expected power function will be calculated such that schedule changes between Settlement Intervals will be ramped during a fourteen (14) minute fixed ramp period starting seven (7) minutes prior to the start of a Settlement Interval. ERCOT will consider energy provided outside of the Resource schedule in the Settlement Interval as a result of ramping an instructed deviation.

6.10.4.3 Balancing Energy Power Schedule

For performance measurement purposes, ERCOT shall calculate for each QSE the Balancing Energy power schedule for the expected power resulting from the change in deployment of Balancing Energy Service. The Balancing Energy power schedule will ramp to the new deployment level during a fixed ramp period starting five (5) minutes prior to the target service interval and ending five (5) minutes after the start of the target service interval.

[PRR803: Replace the paragraph above with the following upon system implementation:]

For performance measurement purposes, ERCOT shall calculate for each QSE the Balancing Energy power schedule for the expected power resulting from the change in deployment of Balancing Energy Service. The Balancing Energy power schedule will ramp to the new deployment level during a fixed ramp period starting seven (7) minutes prior to the target service interval and ending seven (7) minutes after the start of the target service interval.

6.10.4.4 Schedule Control Error

ERCOT will calculate the following for each QSE for each two-second period:

SCE = Actual Generation

\+ Load Resource Response to Instructions

– Base Power Schedule

– Sum of any Dynamic Resource Power Schedules

– Expected Automatic Response due to frequency of the QSE's portfolio of Resources

– Instructed Ancillary Services power

– The signal sent to ERCOT that is estimated in Real Time representing the real power interrupted in response to the deployment of Balancing Up Load (BUL) for Dynamically Scheduled Load

– Fleet/Zonal OOME Dispatch Instruction

Instructed Ancillary Services = Instructed (Regulation Service

\+ Responsive Reserve

\+ Non-Spinning Reserve

\+ Balancing Energy power schedule)

LaaR response to Instructions is provided for each interruptible LaaR that is indicated available in the Resource Plan according to the following formula:

LaaR response to Instructions = $\sum_{\text{per}}$ LaaR (last telemetered breaker load MW value prior to deployment - current telemetered breaker load MW value)

6.10.5 QSE Real Power Performance Criteria

6.10.5.1 Base Power Schedule Monitoring Criteria

QSEs shall make their Resources operate to the final Resource bilateral schedules as converted to a base power function according to the method specified in Section 6.10.4.2, Base Power Schedule Calculation, except as noted in Section 6.10.6, Ancillary Service Deployment Performance Conditions. Measurement of performance shall be accomplished using the SCE monitoring criteria described in Section 6.10.5.3, SCE Monitoring Criteria.

6.10.5.2 Balancing Energy Performance Monitoring Criteria

QSEs providing only Balancing Energy Services shall declare this intent to ERCOT in the Scheduling Process. On deployment of Balancing Energy Services, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the equivalent power requirement of the Balancing Energy Services Dispatch Instruction. ERCOT calculation of SCE for each two (2) seconds and integrated over the

Settlement Interval will indicate the average performance of the QSE to supply Balancing Energy Services. Measurement of performance shall be accomplished using the SCE monitoring criteria described in Section 6.10.5.3, SCE Monitoring Criteria.

On deployment of BULs, the QSE shall control its Loads to the difference between its Scheduled power and the BUL instructed amount. ERCOT, at a time established at its discretion, shall determine the base Load of the sum of all Loads qualified by the QSE as BUL Resources by obtaining actual meter data from IDR meters or directly from the TDSP who has agreed to Supply the data. The base Load is determined by finding the average actual metered energy during the same interval as the instruction to deploy BUL from the previous ten (10) days (in the case of weekday deployment) or six (6) days (in the case of weekend or holiday deployment). Days in which BUL instructions occurred during the same interval are ignored. If the instruction to deploy occurs on a weekday, only weekdays are included in the average. If the instruction to deploy occurs on a weekend, only weekend days and ERCOT-defined holidays are included in the average.

ERCOT shall also integrate for each Settlement Interval the signal provided by the QSE representing the amount of BUL power deployed. The expected total reduction of Load shall be determined by subtracting the integrated signal for each interval from the base Load as determined above. Control performance of the QSE providing BUL shall be deemed satisfactory when during the first hour in which BUL is deployed in an Operating Day, the actual metered Load for any Settlement Interval during the hour is equal to or less than the amount of energy expected. Failure of the QSE to provide satisfactory control performance during the first hour in which BUL is deployed in an Operating Day will cause ERCOT to withhold payments for any capacity provided as BUL for the Operating Day. Failure of a BUL to provide at least ninety percent (90%) of the expected total Load during the first hour of deployment for three (3) Operating Days in a year will disqualify a BUL.

The QSE will have to requalify the specific BUL; however, there will be a ninety (90) day waiting period before the BUL can be requalified. To be requalified, the BUL will have to successfully reduce Load during the following BUL requalification test. The QSE shall nominate to ERCOT the BUL which it wishes to requalify. During a period of time mutually agreed to by the QSE and ERCOT, at a specific time selected by ERCOT, the ERCOT operator will notify the QSE that it wants to reverify the BUL’s ability to provide ERCOT with the appropriate Load reduction. Upon receipt of the ERCOT Notification, the QSE Operator will immediately initiate the BUL reduction and provide ERCOT with the appropriate signal representing the amount of Load to be reduced. Upon completion of the deployment interval, the ERCOT Testing Operator shall call the QSE and notify it that the test is complete. At this time the deployed Resources may be restored to their normal state.

Load used to provide BUL Resources shall be requalified for correct operation by comparing the average energy in a Settlement Interval as recorded on IDR meters to the expected reduction in total Load indicated by the QSE’s signal to ERCOT. Once ERCOT has verified that it actually received the committed Load reduction from the BUL, the QSE will be notified when the BUL can resume providing Balancing Up Energy Service. If the BUL fails the requalification test, the QSE may request an additional requalification test for that BUL, but the BUL shall not be allowed to have more than three (3) requalification tests in a year.

[PRR311 and PRR484: Replace the above two paragraphs with the following upon system implementation:]

On deployment of BULs, the QSE shall control its Loads to the difference between its scheduled power and the BUL instructed amount. ERCOT, at a time established at its discretion, shall determine the base Load of the sum of all Loads qualified by the QSE as BUL Resources by obtaining actual meter data from IDR meters, or from a sample of Loads controlled under a Direct Load Control (DLC) program qualified in accordance with Section 18.7.2, Load Profiling of ESI IDs Under Direct Load Control, or directly from the TDSP who has agreed to supply the data. While IDRs must normally be present on all Loads providing BUL Resources, IDRs may be installed and read on a sample of the Loads qualified by a QSE as a BUL Resource, provided the Loads are sampled in accordance with Section 18.7.2, Load Profiling of ESI IDs under Direct Load Control.

Except in the case of a qualified DLC program, the base Load is determined by finding the average actual metered energy during the same interval as the instruction to deploy BUL from the previous ten (10) days (in the case of weekday deployment) or six (6) days (in the case of weekend or holiday deployment). In the case of a qualified DLC program, the base Load is the representative sample metered energy administered in accordance with Section 18.7.2, Load Profiling of ESI IDs Under Direct Load Control. Days in which BUL instructions occurred during the same interval are ignored. If the instruction to deploy occurs on a weekday, only weekdays are included in the average. If the instruction to deploy occurs on a weekend, only weekend days and ERCOT-defined holidays are included in the average. For small Customer Load management programs, base Load for each interval is determined from the aggregated appropriate baseline Load Profile for participating customers assuming the Load management program is not in operation.

ERCOT shall also integrate, for each Settlement Interval, the signal provided by the QSE representing the amount of BUL power deployed. The expected total reduction of Load shall be determined by subtracting the integrated signal for each interval from the base Load as determined above. For small Customer Load management programs during each interval, the expected total reduction of Load shall be determined by subtracting the aggregated participating Customer Load during operation of the Load management program, which is calculated from the appropriate Load Profile, from the base Load for these customers as calculated above. Control performance of the QSE providing BUL shall be deemed satisfactory when during the first hour in which BUL is deployed in an Operating Day, the actual metered Load for any Settlement Interval during the hour is equal to or less than the amount of energy expected. Control performance of the QSE providing BUL through a qualified DLC program shall be deemed satisfactory when, during the first hour in which BUL is deployed in an Operating Day, the estimated actual Load developed from the representative sample administered in accordance with Section 18.7.2, Load Profiling of ESI IDs Under Direct Load Control, for any Settlement Interval during the hour is equal to or less than the amount of energy expected. Failure of the QSE to provide satisfactory control performance during the first hour in which BUL is deployed in an Operating Day will cause ERCOT to withhold payments for any capacity provided as BUL for the Operating Day. Failure of a BUL to provide at least ninety percent (90%) of the expected total Load during the first hour of deployment for three (3) Operating Days in a year will disqualify a BUL.

The QSE will have to requalify the specific BUL; however, there will be a ninety (90) day waiting period before the BUL can be requalified. To be requalified, the BUL will have to successfully reduce Load during the following BUL requalification test. The QSE shall nominate to ERCOT the BUL which it wishes to requalify. During a period of time mutually agreed to by the QSE and ERCOT, at a specific time selected by ERCOT, the ERCOT operator will notify the QSE that it wants to reverify the BUL's ability to provide ERCOT with the appropriate Load reduction. Upon receipt of the ERCOT Notification, the QSE Operator will immediately initiate the BUL reduction and provide ERCOT with the appropriate signal representing the amount of Load to be reduced. Upon completion of the deployment interval, the ERCOT Testing Operator shall call the QSE and notify it that the test is complete. At this time the deployed Resources may be restored to their normal state.

Except in the case of a qualified DLC program, Load used to provide BUL Resources shall be requalified for correct operation by comparing the average energy in a Settlement Interval as recorded on IDR meters to the expected reduction in total Load indicated by the QSE's signal to ERCOT. In the case of a qualified DLC program, the base Load is the average energy in a Settlement Interval developed from the representative sample administered in accordance with Section 18.7.2, Load Profiling of ESI IDs Under Direct Load Control. Once ERCOT has verified that it actually received the committed Load reduction from the BUL, the QSE will be notified when the BUL can resume providing Balancing Up Energy Service. If the BUL fails the requalification test, the QSE may request an additional requalification test for that BUL, but the BUL shall not be allowed to have more than three (3) requalification tests in a year.

6.10.5.3 SCE Monitoring Criteria

SCE Monitoring Criteria will be reviewed by the appropriate ERCOT TAC subcommittee and submitted into these Protocols upon approval.

Each QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the equivalent power requirement of any instructed Ancillary Services and other SCE Obligation terms including governor response. Texas Regional Entity (TRE) shall calculate one (1) and ten (10) minute averages of each QSE's SCE. TRE shall also calculate each QSE's participation factor as the ratio of the QSE's Generation Resource scheduled change in the measurement period (one (1) or ten (10) minute) to the total ERCOT Generation Resource scheduled change in the same measurement period. ERCOT shall limit the deployment of RGS to QSEs for each control cycle equal to one hundred twenty five percent (125%) of the total amount of RGS in ERCOT divided by the number of control cycles in ten (10) minutes. Intervals where a QSE's generation level is less than one (1) MW in the measurement period (one (1) or ten (10) minute) will not be included in the calculation of the SCE Monitoring Criteria. Satisfactory control performance of the QSE shall be deemed acceptable when:

(1) The one (1) minute averages of the QSE's SCE meet the following criteria over the calendar month (commonly referred to as SCPS1), and

$$AVG(month)\left[\left(\frac{SCE_1}{ParticipationFactor}\right)*\left(\frac{\Delta F_1}{(10*Bias_1)*\varepsilon^2{}_1}\right)\right]\leq 1$$

(2) The ten (10) minute averages of the QSE's SCE meet the following criteria for ninety percent (90%) of the ten (10) minute periods over the calendar month (commonly referred to as SCPS2).

$$|SCE_{10}|\leq L_{10}*K\sqrt{ParticipationFactor}$$

Where:

SCE_1 is the one (1) minute average of SCE.

SCE_{10} is the ten (10) minute average of SCE.

$Bias_1$ is the one (1) minute average of the ERCOT total bias used in the ACE calculation.

ΔF_1 is the one (1) minute average of frequency deviation from schedule.

Participation Factor is determined by the ratio of the QSE's generation scheduled change for the measurement period (one (1) or ten (10) minute) to total ERCOT generation schedule change for the measurement period (one (1) or ten (10) minute). Generation schedule change per interval is defined as below:

{Absolute Value

[(ResourceSchedule – ResourceSchedulePreviousInterval)

+ (BalancingDeployment – BalancingDeploymentPreviousInterval)]

+ RegulationUpSchedule

+ RegulationDownSchedule}

If this Participation Factor Calculation results in a value of less than one-percent (1%), then one-percent (1%) will be used.

ε_l is a constant derived from the targeted frequency bound. It is the targeted root-mean score of one (1) minute average frequency error from a schedule based on frequency performance over a given year as established according to NERC performance requirements by ERCOT and the appropriate ERCOT subcommittee as assigned by TAC.

L_{10} is a limit to recognize the desired performance of frequency for ERCOT as established according to NERC performance requirements by the appropriate ERCOT subcommittee assigned by TAC. As of July 2003, L_{10} is defined as (1.65 * E_{10} * 10 * $Bias_{10}$) where E_{10} is 0.01315 Hz and $Bias_{10}$

is the ten (10) minute average of the ERCOT total bias used in the ACE calculation.

K is a constant currently set to .81 which is established by the appropriate ERCOT subcommittee as assigned by TAC. *K* should initially be set to .81 to provide an ERCOT wide L_{10} equivalent to the ERCOT wide L_{10} currently used by Control Areas in ERCOT. This constant can be adjusted to ensure correlation between passing the NERC CPS2 criteria and passing the SCE ten (10) minute control limit.

TRE shall determine the QSE SCE performance score on a monthly basis. SCPS2 scores equal to or greater than ninety-percent (90%) will be considered to be in compliance with the SCE Monitoring Criteria. A QSE shall not be in compliance for any month with its score less than ninety-percent (90%) and shall be subject to procedures for non-compliance consistent with Section 6.10.12, Actions for Non-Compliance of the SCE Monitoring Criteria, through Section 6.10.12.5, ERCOT Actions for Non-Compliance.

Forced Derates shall be communicated to ERCOT immediately by voice communication. The QSE representing the Resource will also report any changes in Resource status to ERCOT in the Resource Plan by the beginning of the next hour following the change in status in accordance with Section 5.5.1, Changes in Resource Status.

Startup Loading Failures shall be communicated to ERCOT immediately by voice communication. The QSE representing the Resource will also report any changes in Resource status to ERCOT in the Resource Plan by the beginning of the next hour following the change in status in accordance with Section 5.5.1.

6.10.5.4 Responsive Reserve Services Deployment Performance Monitoring Criteria

QSEs providing Responsive Reserve Services must so indicate in the Scheduling Process. QSEs shall have Resources available to meet the schedule while adhering to the Responsive Reserve Service requirements detailed in the Operating Guides. On deployment of any Responsive Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the instructed Responsive Reserve Service power requirement. ERCOT's calculation of SCE will determine the level of Responsive Reserve Service provided. Satisfactory control performance of the QSE providing Responsive Reserve Services shall be deemed satisfactory when two (2) out of the following three (3) conditions are met:

(1) The QSE's SCE returns to the lesser of its pre-disturbance level or zero (0) within ten (10) minutes of the deployment of RRS.

(2) The QSE's SCE must be above the minimum level at the ten (10) minute point after the deployment of RRS. The minimum level is defined as:

-1 * (Min (20 MW, Max (.007 * actual generation, QSE_L10)))

The QSE_L10 value is defined as the actual value as indicated in the formula in Section 6.10.5.3 (2) (L_{10} * K * SQRT (Participation Factor)) at the ten (10) minute point after the deployment of RRS. The actual generation is the QSE's actual generation at the ten (10) minute point.

(3) The QSE's average SCE for the ten (10) minute period following the RRS deployment must be above the minimum level. The minimum level is defined as:

-1 * Max (QSE_L10, .45 * Max RRS Deployment in 10 minutes)

If a QSE's SCE fails to meet two (2) out of the three (3) criteria stated above, the performance will be recalculated with the frequency bias term removed from the QSE's SCE equation. Based on the criteria above, ERCOT will assign a QSE a "PASS" or "FAIL" grade for that particular RRS deployment.

QSEs providing RRS for deployments lasting less than ten (10) minutes will be considered to have passed that particular deployment. The QSE must deliver the required RRS deployed at least ninety percent (90%) of the time during any single performance interval. A performance interval will be a minimum of two months and a maximum of four months. If a QSE has received twenty (20) deployments within two or three months, then that time period will count as the performance interval. Otherwise, the four month period will count as a performance interval regardless of how many deployments the QSE has received. QSEs must pass four (4) performance intervals out of the last six (6) performance intervals in order to be considered compliant. ERCOT will provide QSEs with monthly scores for informational purposes only.

LaaR deployments will be subject to a different set of compliance monitoring criteria. QSE's will be evaluated on their LaaR portfolio response to an ERCOT Operator's Verbal Deployment Instruction or based on their portfolio automated response to an under-frequency event. Criteria to be used for each event or instruction will be as follows:

(1) A QSE's LaaR portfolio response is expected to be not less than ninety-five percent (95%), nor more than one hundred fifty percent (150%) of the RRS requested, subject to the declared capabilities of the QSE within ten (10) minutes of ERCOT's deployment Dispatch Instruction and maintained until recalled or the QSEs service Obligation expires; and

(2) LaaRs providing a RRS response shall return to their committed operating level of RRS service as soon as practical considering process constraints and performance will be monitored against the requirements identified in Section 6.5.4 (13).

For all frequency deviations exceeding 0.175 Hz, ERCOT shall measure and record each two (2) second scan rate values of real power output for each QSE Resource providing Responsive Reserve Service. ERCOT shall measure and record the MW data beginning one (1) minute prior to the start of the frequency excursion event or Manual / Dispatch Instruction until ten (10) minutes after the start of the frequency excursion event or Manual / Dispatch Instruction. Satisfactory performance is measured by comparing the actual response to the frequency response capability required in the Operating Guides.

Where multiple observations of operating response are available, the QSE must deliver the required frequency response capability seventy-five percent (75%) of the time during any single calendar quarter.

6.10.5.5 Non-Spinning Reserve Deployment Services Performance Monitoring Criteria

QSEs providing Non-Spinning Reserve Services must so indicate in the Scheduling Process. On deployment of any Non-Spinning Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the instructed Non-Spinning Reserve power requirement. ERCOT's calculation of SCE will determine the level of Non-Spinning Reserve provided.

Control performance of the QSE providing Non-Spinning Reserve Services shall be deemed satisfactory when a QSE's average SCE must be greater than its average -1 * QSE_L10 for at least 75% of all 5-minute intervals for each hour of non-zero deployment of NSRS where the QSE_L10 value is defined as the actual value as indicated in the formula in Section 6.10.5.3 (2) (L_{10} * K * SQRT (Participation Factor)).

[PRR436: Add the following paragraph to Section 6.10.5.5 upon system implementation:]

During periods when the Load level of a LaaR has been affected by a Dispatch Instruction from ERCOT, the performance of a LaaR in response to a Dispatch Instruction will be determined by subtracting the LaaR's actual Load response from its baseline. 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.

The baseline capacity is calculated by measuring the average of the real power consumption for the four (4) Settlement Intervals prior to the Dispatch Instruction. During hours when the Load level of a LaaR has not been affected by a Dispatch Instruction from ERCOT, the Resource quantity provided by the LaaR scheduled or selected by ERCOT to provide Non-Spinning Reserve Service shall be measured as the LaaR's average Load level during the hour.

6.10.5.6 Combinations of Reliability Services Monitoring Criteria

QSEs providing any combination of services shall control their Resources to the additive result of any number of Dispatch Instructions deployed simultaneously. On deployment of any Balancing Energy, Regulation, Responsive Reserve, and Non-Spinning Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the additive power requirement of each effective Dispatch Instruction. Satisfactory control performance of the QSE providing any combination of services will be determined by a combination of the following:

(1) The criteria for SCE Monitoring at all times with exclusions as noted in Section 6.10.6; and

(2) The criteria for Responsive Reserve if Responsive Reserve Service is one of the services deployed; and

(3) The criteria for Non-Spinning Reserve Service if Non-Spinning is one of the services deployed.

6.10.6 Ancillary Service Deployment Performance Conditions

TRE shall determine the performance of providers of QSE SCE performance under normal operating conditions. TRE shall remove from consideration of average performance of a QSE any period during which any of the following events has occurred and which does not have a passing score.

(1) The two and a half (2.5) hour period after the QSE has experienced a Forced Outage, Forced Derate, or Startup Loading Failure (excluding operator error Startup Loading Failures) of a Generation Resource and is under-generating or because of an unexpected loss of Private Use Network Load that is over-generating. To be considered for exclusion from performance non-compliance, the QSE must provide TRE with the following documentation regarding each Forced Derate or Startup Loading Failure:

   (a) Its generation log documenting the Forced Derate or Startup Loading Failure;

   (b) QSE Resource Plan for the intervals prior to, and after the event; and

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

(2) The entire Settlement Interval(s) for all QSEs in which ERCOT has deployed or recalled Balancing Energy in response to an Unusual Event;

(3) The entire Settlement Interval(s) in which ERCOT has issued a verbal Dispatch Instruction;

(4) The period where ERCOT issues unit-specific instructions to any QSE outside of the unit's capabilities;

(5) The period where ERCOT issues portfolio instructions to any QSE outside of the QSE's portfolio capabilities, including the QSE's bid ramp rate;

(6) The entire Settlement Interval(s) in which a QSE is ramping into (from time of notification to time of deployment) or out of (from end of deployment to thirty (30) minutes later) a NSRS deployment;

(7) If requested the day before the test by a QSE, the entire Settlement Interval(s) in which a QSE is performing tests required in Section 6.10, Ancillary Service Qualification, Testing and Performance Standards, and other regulatory agency-required tests;

(8) The entire Settlement Interval(s) in which a QSE's Resource Plan shows only Uncontrollable Renewable Resources On-line;

(9) The entire Settlement Interval(s) in which a QSE has deployed energy from extra capacity during an Emergency Notice or EEA;

(10) The lesser of:

(a) The time it takes to comply with the second Dispatch Instruction; or

(b) Forty-five (45) minutes following the second Dispatch Instruction, when ERCOT sends a Dispatch Instruction to a QSE whose only controllable Generation Resource is in the West Congestion Zone to decrease the output from that Generation Resource and, within forty-five (45) minutes of sending that Dispatch Instruction, sends a second Dispatch Instruction to the same QSE to increase the output from that Generation Resource, provided that the QSE did not provide any Ancillary Service other than Balancing Energy Service from that Generation Resource during the period removed from consideration of the QSE's average SCE performance; and

[PIP112: Add item #11 below to the list and renumber the existing (11) to (12) when BUL is implemented:]

(11) If requested by a QSE, up to three (3) scheduling hours following an instruction issued by ERCOT to recall previously deployed Responsive Reserve, Non-Spin or Balancing Energy Up Services provided from replacement capacity that is using qualified Load as the QSE's Resource; and

(11) Certain other periods of abnormal operations as determined by ERCOT.

6.10.7 Individual Resource Dispatch Performance

QSEs may receive Dispatch Instructions to operate a specific Resource within limitations specified for an individual Resource. The QSE shall conform to the limitations restricting Resource loading for the effective time of the Dispatch Instruction to within two (2) MW of the requested limitation.

6.10.8 Replacement Reserve and OOMC Service Performance Criteria

QSEs awarded Replacement Reserve or OOMC Service to bring a Generation Resource unit On-line or make available LaaR for Replacement Reserve Service shall make a good faith effort to cause their Resources to be available for required Balancing Energy instructions at the time requested by ERCOT. Any QSE that anticipates for any reason it may not be able to honor its commitment because of unexpected problems shall notify ERCOT immediately. ERCOT will monitor the Real Time telemetry of the subject Resource breakers and megawatt output to determine if it is available as purchased. Performance shall be satisfactory if the Resource is brought On-line or made available and the QSE makes available required Balancing Energy bids, which, for a LaaR, is at least in the amount of the capacity of the awarded Resource, and, for an awarded Generation Resource, is the High Sustainable Limit minus the Low Sustainable Limit throughout the period requested. QSEs failing to bring the Generation Resource On-line or make the LaaR active shall not be entitled to compensation for the intervals that the capacity was not available. QSEs failing to provide the required levels of Balancing Energy bids in response to the awards shall not be entitled to compensation for that amount of capacity not made available.

[PRR436: Replace Section 6.10.8 with the following upon system implementation:]

QSEs awarded Replacement Reserve or OOMC Service to bring a Generation Resource unit On-line or make available LaaR for Replacement Reserve Service shall make a good faith effort to cause their Resources to be available for required Balancing Energy instructions at the time requested by ERCOT. Any QSE that anticipates for any reason it may not be able to honor its commitment because of unexpected problems shall notify ERCOT immediately. ERCOT will monitor the Real Time telemetry of the subject Resource breakers and megawatt output to determine if it is available as purchased. Performance shall be satisfactory if the Resource is brought On-line or made available and the QSE makes available required Balancing Energy bids, which, for a LaaR, is at least in the amount of the capacity of the awarded Resource, and, for an awarded Generation Resource, is the High Sustainable Limit minus the Low Sustainable Limit throughout the period requested. During periods when the Load level of a LaaR has been affected by a Dispatch Instruction from ERCOT, the performance of a LaaR in response to a Dispatch Instruction will be determined by subtracting the LaaR's actual Load response from its baseline. 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. The baseline capacity is calculated by measuring the average of the real power consumption for the four (4) Settlement Intervals prior to the Dispatch Instruction. During hours when the Load level of a LaaR has not been affected by a Dispatch Instruction from ERCOT, the Resource quantity provided by a LaaR scheduled or selected by ERCOT to provide Replacement Reserves shall be measured as the LaaR's average Load level during the hour. QSEs failing to bring the Generation Resource On-line or make the LaaR active shall not be entitled to compensation for the intervals that the capacity was not available. QSEs failing to provide the required levels of Balancing Energy bids in response to the awards shall not be entitled to compensation for that amount of capacity not made available.

6.10.9 Reactive Power Supply from Generation Resources Required to Provide VSS Performance Criteria

(1) ERCOT will maintain a performance log of QSEs acknowledgements of Dispatch Instructions concerning scheduled voltage or scheduled Reactive output requests. QSEs

responding in less than two (2) minutes from the time of issuance of such requests shall be deemed satisfactory.

(2) ERCOT shall monitor the Automatic Voltage Regulator, as required in Section 6.5.7, Voltage Support Service, to assure that it is on and operating automatically at least ninety-eight percent (98%) of the time in which the QSE is providing the Reactive Power Supply from Generation Resources required to provide VSS. The percentage is calculated as: Time (Automatic Voltage Regulator is on while providing Service) / (Total Time Providing Services) × 100%.

(3) Except under Force Majeure conditions or ERCOT-permitted operation of the generating unit, failure of a Generation Resource required to provide VSS to provide either leading or lagging reactive up to the required capability of the unit upon request from a TSP or ERCOT may, at the discretion of ERCOT, be reported to the ERCOT Compliance Office.

(4) Except under Force Majeure conditions or ERCOT-permitted operation of the generating unit, if a Generation Resource required to provide VSS fails to maintain transmission system voltage at the point of interconnection with the TSP within two percent (2%) of the scheduled voltage while operating at less than the maximum reactive capability of the generating unit, ERCOT may, at its discretion, report this to the ERCOT Compliance Office.

(5) The ERCOT Compliance Office will investigate claims of alleged non-compliance and Force Majeure conditions, and address confirmed non-compliance situations. The ERCOT Compliance Office will advise the Generation Resource, its QSE, ERCOT, and the TSP planning and operating staffs of the results of such investigations.

6.10.10 System Black Start Capability Performance Criteria

The Black Start Unit shall maintain qualified System Black Start Capability, with the declared capacity and capabilities of the Resources continuously; except during those periods allowed for routine maintenance. During a system restoration emergency, the provider shall respond to the instructions of ERCOT, subject to the declared capacity and capabilities of the system Black Start Capability Generation Resources.

The Black Start Resource shall complete all initial and ongoing qualification requirements.

6.10.11 ERCOT Operations Performance

(1) ERCOT shall continuously self-assess its operations and report to all Market Participants its performance in controlling the ERCOT Control Area according to requirements and criteria established by the Operating Guides and NERC Policy and Standards for operation of Control Areas. ERCOT shall report all substandard operations to the ERCOT Technical Advisory Committee and to the NERC Compliance and Enforcement Committees.

(2) ERCOT shall publish for all Market Participants the total amount of Regulation Up energy deployed and the total amount of Regulation Down energy deployed in each Settlement Interval.

(3) ERCOT shall provide monthly a report analyzing the accuracy of each Operating Day's Load forecast that was issued at 0600 the Day Ahead of the Operating Day. ERCOT shall make similar comparisons for the 1100 forecast and the forecast in effect at midnight of the start of the Operating Day. In its reports, ERCOT shall statistically analyze the expected error in energy and peak forecasting.

(4) ERCOT shall publish for all Market Participants the percentage of the Bid Stack awarded for Balancing Energy Service for each Settlement Interval that ERCOT deploys any Non-Spinning Reserve Service.

(5) ERCOT shall provide a monthly report showing the average percentage of the Bid Stack award for Balancing Energy Service for the Settlement Intervals that ERCOT deploys Non-Spinning Reserve Service for the month.

(6) ERCOT shall provide a monthly report by the 20^{th} day of the following month showing the quantity of Replacement Reserve Service (RPRS) procured by hour for system capacity based on the Day Ahead estimate of total ERCOT Load versus the quantity of RPRS that, in hindsight, would have been the proper amount to procure based on actual average adjusted metered Load. This theoretical amount of RPRS procurement shall be calculated as the difference between the actual average adjusted metered ERCOT Load (for an hour) minus the Day Ahead Resource Plan generation on-line used before the RPRS market is run for the hours when RPRS is procured by ERCOT.

[PRR673: Add the language below upon system implementation:]

(7) ERCOT shall post no later than two Business Days after the Operating Day the total ERCOT score for the CPS1 metric. This data shall include the daily average of ERCOT's CPS1 and the current average for the month.

6.10.12 Actions for Non-Compliance of the SCE Monitoring Criteria

6.10.12.1 SCE Non-Compliance Remedies

TRE shall calculate the SCPS2 score for each QSE each month, taking into consideration excluded intervals with valid exemptions, and determine if a potential non-compliance with the SCPS2 metric occurred. TRE will notify the QSE of its potential non-compliance and allow the QSE ten (10) Business Days to respond with evidence to modify its score. TRE will make the final determination of SCE non-compliance.

Non-compliance with the SCPS2 score will be reported to ERCOT for calculation of the SCE Performance Charge and the non-compliance report will be forwarded to the Public Utility Commission of Texas (PUCT).

(1) Upon a QSE's first (1^{st}) non-compliance with the SCE Monitoring Criteria as described in Section 6.10.5.3, SCE Monitoring Criteria, within a rolling twelve (12) month period:

(a) [*SCPS2 scores below ninety-percent (90%) and greater or equal to eighty-percent (80%)*] ERCOT will assess QSE the SCE Performance Charge (Section 6.10.12.3, SCE Performance Charge) and PUCT Staff will send QSE a Notification letter.

(b) [*SCPS2 scores below eighty-percent (80%)*] In addition to item (1)(a) above, PUCT Staff may recommend any action as allowed by Public Utility Regulatory Act, Title II, TEX UTIL. CODE ANN. (Vernon 1998 & Supp. 2007) (PURA) and the PUCT Substantive Rules.

(2) Upon a QSE's second (2^{nd}) non-compliance with the SCE Monitoring Criteria within a rolling twelve (12) month period:

(a) [*SCPS2 scores below ninety-percent (90%) and greater or equal to eighty-percent (80%)*] ERCOT will assess QSE twice the SCE Performance Charge and PUCT Staff will send QSE a Notification letter.

(b) [*SCPS2 scores below eighty-percent (80%)*] In addition to item (2)(a) above, PUCT Staff may recommend any action as allowed by PURA and the PUCT Substantive Rules.

(3) Upon a QSE's third (3^{rd}) non-compliance with the SCE Monitoring Criteria within a rolling twelve (12) month period:

(a) [*SCPS2 scores below ninety-percent (90%) and greater or equal to eighty-percent (80%)*] ERCOT will assess QSE twice the SCE Performance Charge and PUCT Staff may recommend any action as allowed by PURA and the PUCT Substantive Rules.

(b) [*SCPS2 scores below eighty-percent (80%)*] In addition to item (3)(a) above, ERCOT will limit the QSE's rights to provide RGS (Section 6.10.12.2, ERCOT's Authority to Limit a QSE's Right to Provide Regulation Service Due to SCE Non-Compliance).

(4) Upon a QSE's fourth (4^{th}) non-compliance with the SCE Monitoring Criteria within a rolling twelve (12) month period:

(a) [*SCPS2 scores below ninety-percent (90%)*] ERCOT will assess QSE twice the SCE Performance Charge, limit the QSE's rights to provide RGS, and PUCT

Staff may recommend any action as allowed by PURA and the PUCT Substantive Rules.

(5) For subsequent QSE non-compliance with the SCE Monitoring Criteria within a rolling twelve (12) month period:

(a) [*SCPS2 scores below ninety-percent (90%)*] ERCOT will assess QSE twice the SCE Performance Charge, limit the QSE's rights to provide RGS, consider revocation of any or all Ancillary Service qualifications of that QSE (Section 6.10.12.5, ERCOT Actions for Non-Compliance), and PUCT Staff may recommend any action as allowed by PURA and the PUCT Substantive Rules.

Compliance with Section 6.10.5.3 will be reviewed for a rolling twelve (12) month period, such that the first incidence of non-compliance following a twelve (12) month period of compliance will be subject to items (1)(a) and (1)(b) above.

6.10.12.2 ERCOT's Authority to Limit a QSE's Right to Provide Regulation Service Due to SCE Non-Compliance

TRE will notify ERCOT and the QSE of the QSE's third (3^{rd}) or subsequent non-compliance with the SCE Monitoring Criteria within a rolling twelve (12) month period. ERCOT will then use its authority to limit a QSE's right to provide RGS prospectively, for a three (3) month period, for all hours of the day due to repeated SCE non-compliance. Items (3) through (5) in Section 6.10.12.1, SCE Non-Compliance Remedies, detail the specific situations for which this limitation would occur. ERCOT shall communicate, and the QSE shall comply with the RGS limit. The QSE would be released from the assessed regulation limitation once it has met a ninety-percent (90%) or greater SCPS2 compliance performance level for at least three (3) consecutive months (which include months in regulation limited three (3) month period)).

ERCOT shall calculate the RGS limit by taking the total number of MWh of Regulation Service Up (RGSU) scheduled and submitted to ERCOT for the month and dividing such quantity by the number of hours in which the QSE submitted RGSU schedules to ERCOT.

$$RSL_{up} = \frac{(RGS_{up})_{mq}}{Hrs_{RGSU}}$$

Where:

RSL	Regulation Service schedule limitation

RGS_{up} Total Regulation Service-Up MWh scheduled and submitted to ERCOT

q QSE

m Monthly total

Hrs_{RGSU} Total number of hours in which Regulation Service-Up schedules were submitted to ERCOT over the previous three (3) months.

6.10.12.3 SCE Performance Charge

For the month being analyzed, a QSE at or above the target level for the ten (10) minute criteria for SCE performance, the SCE Performance Charge will be zero (0).

If a QSE falls below the target level for the ten (10) minute criteria for SCE performance for the month being analyzed, ERCOT shall calculate the number of additional 10 minute periods that the QSE needed to have achieved the target level. For each ten (10) minute period below the target level, ERCOT shall calculate the potential performance charge as the simple average Market Clearing Price for Capacity (MCPC) of RGSU and Regulation Service Down (RGSD) for that period multiplied by the absolute value of average SCE during that period. If the MCPC for RGSU or RGSD is negative, ERCOT will set that price equal to zero (0) in calculating the SCE Performance Charge. The QSE's monthly Performance Charge shall be calculated as the sum of the highest cost ten (10) minute periods which were below the target level with the number of periods equal to those required to have met the target level.

$$AINT_{qm} = 90\% * MINT_{qm} – PINT_{qm}$$

For each ten (10) minute interval below target level:

$$INTCHG_{iq} = SAMCPC_i * ABS(SCE_{iq})*SF_m/6$$

$$SAMCPC_i = \Sigma (MCPC_{RGUP} + MCPC_{RGDN})/2$$

$$PCHSCE_{qhm} = \text{SUM of } AINT_q \text{ Greatest } \quad INTCHG_{iq}$$

Where:

q QSE

m Month interval

i 10-minute interval below target level

h Hour interval

$MINT_{qm}$ 10-minute intervals measured for compliance

$PINT_{qm}$ 10-minute intervals meeting compliance measure

SF	Scale Factor. For each month interval the Scale Factor is set to one (1) when ERCOT's CPS1 score is equal to or above 125. The Scale Factor is increased 0.1 above 1.0 for each point scored below 125 with a maximum value of two (2)
$AINT_{qm}$	Additional 10-minute intervals needed to achieve target
$INTCHG_{qi}$	Potential 10-minute interval performance charge
$SAMCPC_{i}$	Simple average of RGSU and RGSD MCPC for the hour
SCE_{i}	Average SCE for the interval
$PCHSCE_{qhm}$	SCE Performance Charge

6.10.12.4 SCE Performance Credit

Receipts for SCE Performance Charges shall be allocated, as a credit, to QSEs with an SCE Compliance Score above the target level for the month being analyzed. The SCE Performance Credit shall be calculated as follows:

$\mathbf{PCRSCE_{phm}} = \mathbf{-1 * SUM(PCHSCE_{qhm})}$Where:

$PCRSCE_{phm}$	SCE Performance Credit, by QSE
$PCHSCE_{qhm}$	SCE Performance Charge, by QSE

The Performance Charges collected by ERCOT shall be allocated to all QSEs that pass the SCE performance measurement (ninety percent (90%) or greater score) for the month. ERCOT shall distribute the payments on a pro-rata share of total 'Regulation supplied' basis, calculated over the set of QSEs that passed the performance measure for the month. To calculate the total RGS schedule for each QSE passing the performance measure, ERCOT shall sum the schedules over the month for RGSU and RGSD.

ERCOT shall allocate the Performance Charges collected for each month to QSEs that pass the performance criteria for the month, as follows:

$$PCRSCE_{ahm} = SUM(PCHSCE_{qhm})*RGPR_{ahm}$$

Where:

$PCRSCE_{phm}$	SCE Performance Credit, by QSE, for QSEs passing the performance measure
$PCHSCE_{hm}$	SCE Performance Charge
$RGPR_{ahm}$	Regulation market participation ratio

q	QSE
a	A QSE passing performance measure
p	QSEs passing performance measure

For each QSE that passes the performance measure, the QSE Participation Ratio is determined on the basis of its actual participation in the scheduled supply of RGSU and RGSD. The Participation Ratio shall be calculated as follows:

$$RGPR_{ahm} = \frac{(RGS_{uphm} + RGS_{downhm})_a}{SUM(RGS_{uphm} + RGS_{downhm})_p}$$

$RGPR_{ahm}$	Regulation market Participation Ratio
a	Individual QSE that passed monthly performance measure
p	QSEs passing performance measure
RGS_{uphm}	Total RGSU MW scheduled for the hour per month
RGS_{downhm}	Total RGSD MW scheduled for the hour per month

6.10.12.5 ERCOT Actions for Non-Compliance

ERCOT may revoke any or all Ancillary Service qualifications of any QSE providing an Ancillary Service(s) for continued failure to comply with required performance standards.

ERCOT may revoke the Ancillary Service qualification of any LaaR for failure to comply with the required performance standards. Specifically, if a LaaR that is providing RRS fails to respond with at least ninety-five-percent (95%) of its scheduled capacity within ten (10) minutes of an ERCOT Dispatch Instruction, that response shall be considered a failure. Two (2) LaaR performance failures within any rolling one (1) year period shall result in disqualification of that LaaR. After six (6) months of disqualification, the LaaR may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified LaaR successfully passes a new actual deployment qualification test as specified in Section 6.10.2, General Capacity Testing Requirements.

Failure to deliver energy resulting from a valid Dispatch Instruction is cause for ERCOT, at ERCOT's option, to withhold payment for any Ancillary Services purchased and not delivered.

TRE will make information relative to each QSE's performance as well as ERCOT's performance, available to Market Participants on a monthly basis, subject to the provisions of Section 1.3.1, Restrictions on Protected Information.

6.10.12.6 Settlement Timeline and Dispute Process

ERCOT shall process the SCE Performance Charges and payments for a month within ten (10) Business Days after TRE issues final scores. ERCOT will apply debits and credits onto Settlement Statements on a scheduled Final Settlement Statement of its choosing and in accordance with Section 9.2, Settlement Statements.

ERCOT may issue a Resettlement Statement for the monthly SCE Performance Charges and payments if required due to approved disputes or corrections. Any such disputes must be submitted and approved thirty (30) days prior to the scheduled date for issuance of the True-Up Settlement Statement for the last day of the month in question. ERCOT may utilize a manual entry to process any Resettlement Statements necessary on a scheduled True-Up Settlement Statement for an Operating Day of the month being analyzed.

Market Participants disputing their SCE scores pursuant to Section 6.10.5, QSE Real Power Performance Criteria, and Section 6.10.6, Ancillary Service Deployment Performance Conditions, will make disputes known to the ERCOT Compliance Department prior to the date on which ERCOT issues the initial monthly settlement. After the initial SCE performance monthly settlement, Market Participants will submit disputes relating to SCE performance calculations in accordance with Section 9.5, Settlement and Billing Dispute Process.

6.10.13 Emergency Interruptible Load Service Qualification, Testing and Performance Standards

6.10.13.1 Qualification of EILS Resources and their QSEs

(1) In order to qualify as an EILS Resource, a Load must meet the following requirements:

(a) The Entity responsible for the Load must be registered with ERCOT.

(b) ERCOT must receive confirmation of IDR metering for the Load. If the Load's IDR meter is not used for settlement with ERCOT, then the IDR meter and the method and format used to collect and transfer the meter data are subject to ERCOT approval. ERCOT shall detail its requirements for non-settlement IDR meters and data in a Technical Requirements document to be issued with the Request for Proposal prior to each Contract Period. This subsection applies to meters behind a Non-Opt-In Entity (NOIE) meter point and behind a Private Use Network's settlement meter point.

(c) ERCOT must review IDR data from the most recent available twelve (12) month period to determine the Load's baseline consumption and either confirm that the Load is eligible for the default baseline or assign the Lload to the alternate baseline if the Load is not eligible for the default baseline.

(d) The EILS Resource, upon selection must execute a Standard Form EILS Agreement with ERCOT.

(2) In order to qualify as a QSE capable of representing EILS Resources, a QSE must be qualified to provide Ancillary Services and be capable of communicating with its EILS Resources in a manner that will allow the EILS Resources to meet their performance obligations.

6.10.13.2 Testing of EILS Resources

ERCOT may conduct a full Load- shedding test of any contracted EILS Resource at any time at ERCOT's discretion. Any such test will not be counted as one of the EILS Resource's two maximum deployments in a contract period. EILS Resources may be tested only during EILS Contract Periods in which they have entered a contract to provide EILS services. A full Load-shedding test shall be deemed to be successful if the EILS Resource sheds at least 95% of its contracted Load, based on its assigned baseline. An EILS Resource that successfully completes an ERCOT-conducted full Load-shedding test shall not be subject to an additional full Load-shedding test for at least three-hundred and sixty-five (365) days. In addition, an EILS Resource that meets its performance obligations for any EILS Dispatch Instruction shall not be subject to a full Load- shedding test for at least the following three hundred and sixty-five (365) days.

6.10.13.3 Performance Criteria for EILS Resources

(1) EILS Default Baseline:

(a) As part of each EILS procurement process, ERCOT shall establish a unique baseline for each EILS Resource in an EILS bid, including each Electric Service Identifier (ESI ID) if participating in an EILS aggregation. This baseline will be considered the default baseline for EILS Resources.

(b) The baseline has two (2) purposes:

(i) To verify or establish an EILS Resource's maximum bid capacity; and

(ii) To verify the EILS Resource's performance, as compared to its contracted capacity, during an EILS deployment event.

(c) In order to determine a baseline for each EILS Resource, ERCOT will create a default baseline formula to predict the interval Load based on variables which will include an ESI ID's historic Load data, weather, time of day and other relevant calendar information. ERCOT may use other data variables in the default baseline formula at ERCOT's sole discretion, if ERCOT determines the additional data will enhance the accuracy of the default baseline. Development of the default baseline for each EILS Resource will be consistent with practices used in developing ERCOT Load Profile models. The methodology for developing the default baseline formula will be documented and published on ERCOT's Market Information System (MIS).

(d) ERCOT will establish the default baseline for an aggregated EILS Resource by adding the default baselines of the individual ESI IDs in the aggregation. The performance of an aggregated EILS Resource shall be verified by ERCOT at the EILS Resource level.

(e) ERCOT will develop a default baseline for each EILS Resource by analyzing fifteen (15) minute interval usage data for the most recent twelve (12) month period available. ERCOT may use additional historic data at its sole discretion. Upon request, ERCOT shall provide the historical data used to develop the default baseline for an EILS Resource to the Entity responsible for that EILS Resource.

(f) Based on ERCOT's analysis of data in establishing a default baseline for an EILS Resource, ERCOT may reduce the amount of capacity an EILS Resource may be awarded in a given EILS Contract Period.

(g) Upon request, ERCOT shall provide default baseline analysis results for an EILS Resource to the Entity representing that EILS Resource.

(2) Alternate EILS Baseline Using Twelve (12) Month Average:

(a) ERCOT shall apply its default baseline formula to all EILS Resources unless, in ERCOT's reasonable discretion, a sufficiently accurate baseline cannot be established due to the characteristics of the Load or Loads within an EILS Resource. In such cases, ERCOT may apply a single alternate baseline formula to all ESI IDs within such EILS Resource.

(b) Under the alternate baseline formula, ERCOT shall calculate an EILS Resource's average (mean) IDR-metered Load (MWh) over the most recent available twelve (12) month period. ERCOT will establish an adjusted MW capacity for each EILS Resource for the applicable EILS Time Period, based upon the difference between this average Load calculation (MWh) and the EILS Resource's declared minimum base Load (MWh). In selecting an EILS Resource with an alternate baseline, ERCOT may award the lesser of the MW bid or the adjusted MW capacity calculated by ERCOT. When deployed by ERCOT, the EILS Resource assigned to an alternate baseline shall curtail down to its minimum base Load or below, regardless of how much actual Load the EILS Resource has On-line at the time of deployment.

(3) End of Contract Period Availability Review and Capacity Payment Adjustments:

(a) Within forty-five (45) days after the end of an EILS Contract Period, ERCOT will complete an availability review for each EILS Resource that was contracted for that EILS Contract Period. In its availability review, ERCOT will determine an "availability factor" for each EILS Resource in that EILS Contract Period.

(b) ERCOT will determine the availability factor for an EILS Resource. An availability factor of ninety-five percent (95%) or greater for an EILS Resource shall result in no reduction in capacity payment for the EILS Resource (*i.e.*, ERCOT shall set the availability factor at one hundred percent (100%)), and the EILS Resource will be deemed to have complied with its availability requirements. If an EILS Resource's availability factor for an EILS Contract Period falls below ninety-five percent (95%), ERCOT shall set the EILS Resource's availability factor at its actual availability factor, and the EILS Resource will be deemed to have failed to meet its availability requirements which may result in a capacity payment adjustment. The calculations to determine the availability factor to be used for settlement purposes are as follows:

$AvailFactor_{qce(tp)r}$ = 1 if $AvailFactor_{qce(tp)}$ >= .95, else $AvailFactor_{qce(tp)r}$ = $AvailFactor_{qce(tp)}$

Where:

q	QSE
c	Contract Period
e	Individual EILS Resource
tp	EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for the EILS Time Period, as defined in the ERCOT Request for Proposal for the EILS Contract Period, as determined in paragraph (3)(b) above
$AvailFactor_{qce(tp)r}$	Revised EILS availability factor for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

(c) For an EILS Resource assigned to the default baseline, ERCOT will calculate its availability factor as follows:

(i) ERCOT will consider the EILS Resource to have been available for any hour in which the EILS Resource's IDR-metered Load was greater than ninety-five percent (95%) of its contracted EILS MW capacity (bid capacity plus declared minimum base Load); otherwise, the EILS Resource will be considered unavailable for that hour. The availability factor will be the ratio of the number of hours the EILS Resource was available during the EILS Contract Period divided by the total hours in the EILS Contract Period.

(ii) Notwithstanding the foregoing, an EILS Resource will be considered as if it were "available" for purposes of determining the availability factor in:

(A) Any hours for which the EILS Resource's QSE notified ERCOT, in a format prescribed by ERCOT, of the EILS Resource's unavailability at least five (5) Business Days in advance, up to a maximum of two percent (2%) of the total contracted hours in the EILS Contract Period;

(B) Any hours in which an EEA was in effect, starting with initiation of EEA Level 1 and including the full EILS recovery period, if applicable; and

(C) Any hours following the second EILS deployment in an EILS Contract Period.

(d) For an EILS Resource assigned to the alternate baseline, ERCOT will calculate its availability factor as follows:

(i) ERCOT shall divide the EILS Resource’s actual average Load per hour (excluding its declared minimum base Load, if any) for the contracted hours in the EILS Time Period and EILS Contract Period by the EILS Resource’s contracted MW bid, provided that the availability factor shall not be greater than one (1).

(ii) In determining the EILS Resource’s average actual Load,

(A) ERCOT shall exclude from the average any hours for which the EILS Resource’s QSE notified ERCOT, in a format prescribed by ERCOT, of the EILS Resource’s unavailability at least five (5) Business Days in advance, up to a maximum of two percent (2%) of the total contracted hours in the EILS Contract Period;

(B) Any hours in which an EEA was in effect, starting with initiation of EEA Level 1 and including the full EILS recovery period, if applicable; and

(C) Any hours following the second EILS deployment in an EILS Contract Period.

(iii) The calculations for the alternate baseline availability factor are as follows:

$$\textbf{AvailFactor}_{\textbf{qce(tp)}} = \textbf{MIN (1, (AV}_{\textbf{(tp)}}\textbf{/(h*BIDValue}_{\textbf{qce(tp)}}\textbf{)))}$$

Where:

q	QSE
c	EILS Contract Period
e	Individual EILS Resource
tp	EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
h	Hour
AV_{tp}	Average Load per hour for contracted EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period (MWh) excluding declared minimum base Load
$BIDValue_{qce(tp)}$	Capacity (MW) for an EILS Resource contracted for an EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for an EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

(e) In the event an EILS Resource that is part of a QSE’s EILS Self-Provision obligation fails to meet its availability requirement for a Contract Period, ERCOT shall adjust the EILS Resource’s QSE’s settlement obligation to reflect the actual availability factor by modifying the term “SP” in Section 6.9.4.4, Settlement Obligation for Emergency

Interruptible Load Service, item (3). An EILS Resource that is part of a QSE's EILS Self-Provision that achieves an availability factor of 0.95 or greater shall be considered to have met its availability requirement.

(4) EILS Resources' Compliance During an EILS Deployment Event and Capacity Payment Adjustments:

(a) Upon ERCOT's issuance of a verbal Dispatch Instruction during EEA Level 2B requesting EILS deployment, EILS Resources assigned to the default baseline must curtail at least ninety-five percent (95%) of available contracted capacity within ten (10) minutes of receiving the verbal Dispatch Instruction and must stay at or below that level until released by ERCOT. EILS Resources assigned to the alternate baseline must curtail to their declared minimum base Load or below, and must stay at or below that level until released by ERCOT.

(b) ERCOT shall measure each EILS Resource's compliance with this requirement through analysis of fifteen (15) minute IDR data from each ESI ID. ERCOT will determine an event performance factor for each EILS Resource based upon this analysis.

(c) For an EILS Resource assigned to a default baseline, the event performance factor (EILFactor) is computed as the arithmetic average of the EILS Interval Performance Factors (EIPFs) for the entire curtailment period.

An EIPF is computed for the EILS Resource for each of the fifteen (15) minute intervals during which an EILS curtailment is required. For an interval, $EIPF_i$ is computed as follows:

$$\mathbf{EIPF_i = Max(Min(((Base\_MWh_i - Actual\_MWh_i) / (IntFrac_i \times BIDValue)),1),0)}$$

Where:

i	Interval
$IntFrac_i$	Interval fraction for that EILS Resource for that interval
$Base\_MWh_i$	Aggregated sum of the baseline MWh values estimated by ERCOT for all ESI IDs in the EILS Resource for that interval
$Actual\_MWh_i$	Aggregated sum of the actual MWh values for all ESI IDs in the EILS Resource for that interval
BIDValue	Aggregated sum of the capacity bid by the EILS Resource in MWh

and where $IntFrac_i$ corresponds to the fraction of time for that interval for which the curtailment period is in effect and is computed as follows:

$$\mathbf{IntFrac_i = (CEndT_i - CBegT_i) / 15}$$

Where:

i	Interval
$CBegT_i$	If the curtailment begins after the start of that interval, the time in minutes from the beginning of that interval to the beginning of the curtailment period, otherwise it is zero (0)
$CEndT_i$	If the curtailment ends during that interval, the time in minutes from the beginning of that interval to the end of the curtailment period, otherwise it is fifteen (15)

(d) For an EILS Resource assigned to an alternate baseline, the EILFactor is computed as the arithmetic average of the EILS Interval Performance Factors (EIPFs) for the entire curtailment period.

An EIPF is computed for the EILS Resource for each of the fifteen (15) minute intervals during which an EILS curtailment is required. For an interval, EIPFi is computed as follows:

For the first interval in the curtailment period,

If $Actual\_MWh_i = 0$ then $EIPF_i = 1$,

Otherwise

$$\mathbf{EIPF_i = Min((((1\text{-}IntFrac_i)\times Actual\_MWh_{i-1} + (IntFrac_i \times Min\_MWh)) / Actual\_MWh_i),1)}$$

For the last interval in the curtailment period,

If $Actual\_MWh_i = 0$ then $EIPF_i = 1$,

Otherwise

$$\mathbf{EIPF_i = Min((((1\text{-}IntFrac_i)\times Actual\_MWh_{i+1} + (IntFrac_i \times Min\_MWh)) / Actual\_MWh_i),1)}$$

And for all other intervals in the curtailment period

If $Actual\_MWh_i = 0$ then $EIPF_i = 1$,

Otherwise

$$\mathbf{EIPF_i = Min(Min\_MWh / Actual\_MWh_i),1)}$$

Where:

i	Interval

$IntFrac_i$	Interval fraction for that EILS Resource for that interval
Min_MWh	Aggregated sum of the minimum base Load in MWh values bid for all ESI IDs in the EILS Resource for that interval
$Actual\_MWh_i$	Aggregated sum of the actual MWh values for all ESI IDs in the EILS Resource for that interval

and where $IntFrac_i$ corresponds to the fraction of time for that interval for which the curtailment period is in effect and is computed as follows:

$$\mathbf{IntFrac_i = (CEndT_i - CBegT_i) / 15}$$

Where:

i	Interval
$CBegT_i$	If the curtailment begins after the start of that interval, the time in minutes from the beginning of that interval to the beginning of the curtailment period, otherwise it is zero (0)
$CEndT_i$	If the curtailment ends during that interval, the time in minutes from the beginning of that interval to the end of the curtailment period, otherwise it is fifteen (15)

(e) In the event that an EILS Resource does not meet its performance obligations according to the appropriate methodology described above, ERCOT may, in its sole discretion, adjust the EILS Resource's event performance factor to reflect the severity of the failure. The event performance factor for an EILS Resource may be any number from zero (0) to one (1), inclusive. An EILS Resource that achieves an event performance factor of 0.95 or greater shall be considered to have met its performance obligations for that event.

(f) In any EILS Contract Period in which ERCOT has issued one (1) or more EILS deployments, if an EILS Resource meets its obligation established in paragraph (4)(a), above, for all intervals of all EILS deployments, its availability factor shall be the greater of the availability factor calculated by ERCOT pursuant to paragraph (3) above or fifty percent (50%), whichever is greater. ERCOT shall apply the calculations below for a EILS Contract Term in which there was at least one (1) EEA event in which ERCOT deployed EILS Resources:

$$\mathbf{AvailFactor_{qce(tp)r} = MAX(.5, AvailFactor_{qce(tp)})}$$

Where:

q	QSE
c	Contract Period
e	Individual EILS Resource
r	Revised pursuant to paragraph (e) or (f) above

tp	EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period, as determined in paragraph (3)(e) above
$AvailFactor_{qce(tp)r}$	Revised EILS availability factor for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

(g) In the event an EILS Resource that is part of a QSE's EILS Self-Provision obligation does not meet its performance requirement, ERCOT shall adjust the EILS Resource's Settlement obligation to reflect the actual performance factor by modifying the term "SP" in Section 6.9.4.4, item (3). An EILS Resource that is part of a QSE's EILS Self-Provision that achieves an event performance factor of 0.95 or greater shall be considered to have met its performance requirement for that EILS event.

6.10.13.4 Suspension of Qualification of EILS Resources and/or their QSEs

(1) If ERCOT determines that an EILS Resource has failed to meet its performance or availability obligations, ERCOT shall suspend the EILS Resource's qualification to participate in EILS for six (6) months. If ERCOT determines that a QSE representing an EILS Resource has failed to meet its EILS obligations under these Protocols, ERCOT shall suspend the QSE's ability to represent EILS Resources for six (6) months. Such suspension may be based on performance during an EILS deployment, the amount of capacity available, the number of hours available, or a combination of the above. ERCOT may consider mitigating factors such as equipment failures and Force Majeure Events in determining whether to assess such penalties. If the EILS Resource or QSE is actively providing EILS at the time it failed to meet its obligations, the six (6) month suspension period shall commence at the end of the current Contract Period. If the EILS Resource or QSE is not providing EILS at the time it failed to meet its obligations, the six (6) month suspension period shall begin immediately upon the finding.

(2) If ERCOT suspends qualification of an EILS Resource or a QSE representing an EILS Resource due to failure to meet performance obligations, ERCOT may revoke and recoup all payments for the EILS Contract Period associated with that EILS Resource.

(3) An EILS Resource may be reinstated only after satisfactorily performing a Load-shedding test conducted by ERCOT, as described in Section 6.10.13.2.

6.11 System-Wide Offer Caps

Balancing Energy Service and Ancillary Services shall be subject to system-wide offer caps as follows.

6.11.1 Balancing Energy Offer Floor

Balancing Energy Service bids shall be no less than -$1,000 per MWh for all Resources. Any Balancing Energy Service bids less than -$1,000 per MWh will be rejected by ERCOT.

6.11.2 Responsive Reserve Service (RRS) Offer Floor

QSEs shall not submit bids to provide RRS at a price less than zero (0) dollars.

6.11.3 Scarcity Pricing Mechanism

ERCOT shall operate the scarcity pricing mechanism ("SPM") as follows:

(1) The SPM shall operate on an annual resource adequacy cycle, starting on January 1 and ending on December 31 of each year.

(2) For each day of the annual resource adequacy cycle, the peaking operating cost ("POC") shall be ten (10) times the daily Houston Ship Channel gas price index for the previous business day. The POC is calculated in dollars per megawatt-hour (MWh).

(3) For the purpose of this section, the Real-Time energy price ("RTEP") shall be measured as the price at an ERCOT-calculated ERCOT-wide hub.

(4) For the current annual resource adequacy cycle, the peaker net margin ("PNM") shall be calculated in dollars per megawatt (MW) on a cumulative basis for all past intervals in the annual resource adequacy cycle as follows:

$\sum((\text{RTEP} - \text{POC}) * (.25))$ for each settlement interval where $(\text{RTEP} - \text{POC}) > 0$

(5) 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 system-wide offer cap on the MIS.

(6) The system-wide offer cap shall be as follows:

(a) The low system-wide offer cap ("LCAP") shall be set on a daily basis at the higher of:

(i) $500 per MWh for Balancing Energy and $500 per MW per hour for Ancillary Services; or

(ii) Fifty (50) times the daily Houston Ship Channel gas price index of the previous business day, expressed in dollars per MWh for Balancing Energy and dollars per MW per hour for Ancillary Services.

(b) Beginning January 1, 2007, the high system-wide offer cap ("HCAP") shall be $1,000 per MWh for Balancing Energy and $1,000 per MW per hour for Ancillary Services.

(c) Beginning March 1, 2007, the HCAP shall be $1,500 per MWh for Balancing Energy and $1,500 per MW per hour for Ancillary Services.

(d) Beginning March 1, 2008, the HCAP shall be $2,250 per MWh for Balancing Energy and $2,250 per MW per hour for Ancillary Services.

(e) At the beginning of each annual resource adequacy cycle, the system-wide offer cap shall be set equal to the HCAP and maintained at this level as long as the PNM during an annual resource adequacy cycle is less than or equal to $175,000 per MW. During an annual resource adequacy cycle, the system-wide offer cap shall be increased as set forth above in items (c) and (d), unless the PNM has exceeded $175,000 per MW by the date specified. If the PNM exceeds $175,000 per MW during an annual resource adequacy schedule, on the next Operating Day, the system-wide offer cap shall be reset to the LCAP for the remainder of that annual resource adequacy cycle.

(7) Any bids that exceed the current system-wide offer cap will be rejected by ERCOT.

ERCOT Protocols
Section 7: Congestion Management

September 1, 2009

7 CONGESTION MANAGEMENT

7.1 Overview of ERCOT Congestion Management

ERCOT employs a Zonal Congestion management scheme that is flow-based, whereby the ERCOT Transmission Grid, including attached Generation Resources and Load, will be divided into a predetermined number of Congestion Zones. Each Congestion Zone is defined such that each Generation Resource or Load within the Congestion Zone boundaries has a similar effect on the loading (Shift Factor) of Transmission Facilities between Congestion Zones. For purposes of solving Zonal Congestion the Shift Factor will be assumed the same for: (i) all Generation Resources deemed likely to vary their output and (ii) Loads within a Congestion Zone. Therefore any imbalance between Loads and Generation Resources in a Congestion Zone will be deemed to have the same impact on a given loading between Congestion Zones.

This Congestion management scheme applies zonal Shift Factors, determined by ERCOT, to predict potential Congestion on Commericially Significant Constraints (CSCs) under the known topology of the ERCOT System. The zonal Shift Factors determined by ERCOT should most closely represent the effect of Generation Resources deemed likely to vary their output and Loads in the Congestion Zone on the CSCs with the current topology of ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential Congestion and notify Market Participants accordingly. ERCOT also uses this scheme, along with other factors, to determine if it should procure Replacement Reserve Service in a Congestion Zone to provide additional Balancing Energy Service to solve expected Congestion. ERCOT will use monthly zonal Shift Factors to post and analyze the Schedule impact on CSCs until it implements calculations of interval Shift Factors in the system.

ERCOT will manage transmission Congestion and categorize the cost of Congestion management as either Zonal Congestion management costs or Local Congestion management Costs. Zonal Congestion management costs are those costs attributable to managing Congestion on CSCs or predefined Closely Related Elements (CRE). The costs of managing Zonal Congestion will be directly assigned to Qualified Scheduling Entities (QSEs) based on the impact of each QSE’s portfolio on CSCs. All other Congestion management costs are considered Local Congestion management costs.

ERCOT will use the Zonal Congestion management model with Shift Factors of Generation Resources and Loads on CSCs and zonal Balancing Energy Service Market Clearing Price for Energy (MCPE) to determine the Shadow Prices of energy across corresponding CSCs. In addition, ERCOT will directly assign to QSEs the costs of any Replacement Reserve Service (RPRS) procured on a zonal basis for Congestion management purposes. ERCOT will use these Shadow Prices in settlement to directly assign to QSEs the cost of managing Zonal Congestion to QSEs.

ERCOT will set the Shadow Price cap at a level that ERCOT calculates to be in alignment with the prevailing system-wide offer cap defined in paragraph (g)(6) of PUCT SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, and Section 6.11, System-Wide Offer Caps. In some cases, such as where two (2) or more CSCs are simultaneously binding, MCPEs may be generated that are at levels higher than the prevailing system-wide offer cap or lower than the Balancing Energy offer floor. When that occurs, ERCOT shall make Real Time or ex-post adjustments to zonal MCPEs to ensure that MCPEs do not exceed the system-wide offer cap or fall below the Balancing Energy offer floor, and adjust CSC Shadow Prices accordingly. ERCOT shall describe the ERCOT Board-approved process for making price adjustments in a Market Operations Bulletin that will be posted on the Market Information System (MIS) Public Area. ERCOT shall send a Notification to Market Participants informing them of any change to the Shadow Price cap at least ten (10) days prior to implementation of the new system-wide offer cap.

The Local Congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model does not use portfolios and uses the current known topology of the transmission system.

ERCOT will Uplift the cost to solve Local Congestion pro rata to each QSE based on its Load Ratio Share.

ERCOT will manage Congestion by:

(1) Evaluating the levels of Zonal Congestion and any other Congestion during the Day Ahead, the Adjustment Period and the Operating Period using appropriate models of the ERCOT Transmission Grid;

(2) Examining the impacts of QSE energy schedules on CSCs;

(3) Posting on the MIS, the total megawatt quantity impacts on every CSC, and allowing QSEs to adjust schedules to mitigate potential Congestion on the CSCs;

(4) Procuring during the Adjustment Period, as needed, RPRS to use with other Resources for which QSEs have submitted Balancing Energy bids to provide sufficient capacity for Balancing Energy flows in the Operating Hour while respecting operational limits of the ERCOT Transmission Grid;

(5) Determining settlement for QSEs providing RPRS procured to manage Congestion; and

(6) Determining settlement for QSEs providing Balancing Energy associated with resolving Zonal Congestion.

ERCOT will carry out these steps in accordance with this Section and the scheduling and Ancillary Service scheduling and selection requirements in Section 4, Scheduling, and Section 6, Ancillary Services, respectively.

7.2 CSC Zone Determination Process

By November 1 of each year, the appropriate ERCOT subcommittee will report to the Technical Advisory Committee (TAC) and ERCOT Board with recommended Commercially Significant Constraint (CSC) designations, resulting Congestion Zone boundaries with any granted exemptions noted, Closely Related Element (CRE) designations and associated Boundary Generation Resources for ERCOT Board review and approval. Shortly after ERCOT Board approval, CSCs and resulting Congestion Zone boundaries and CRE designations will be posted on the Market Information System (MIS). This posting will include a station and bus-by-bus identification of each Congestion Zone.

7.2.1 Process for Determining CSCs

CSCs and resulting Congestion Zones will be reassessed annually by November 1 of each year. ERCOT will use the following process to identify CSCs:

(1) By August 1, of each year, ERCOT will complete an analysis of Load flow data using the latest Steady State Working Group (SSWG) Data Set A summer peak case and will determine expected operating limits, candidate CSCs and associated constraints to be used in the designation of CSCs for the upcoming calendar year using the following steps:

(a) Determination of new CSC candidates:

(i) Candidate CSCs may be determined using transfer analysis between Study Zones. Study Zones are groupings of buses used to test transfer limits using power system simulation tools. These Study Zones can be either of the following: (1) reasonable approximations of the final Congestion Zones, Weather Zones, SSWG Areas or Zones; or (2) any grouping of buses by geographic region or generation/Load pocket. Candidate CSCs shall be: (1) the contingency that causes limiting elements to reach one hundred-percent (100%) of their emergency rating at high transfer levels; (2) the transmission line that is the limiting element under contingencies; or (3) a stability interface limit.

(ii) Candidate CSCs may also be identified through an evaluation of the actual annual Congestion costs from the prior year. For this purpose, Congestion costs include the cost of any zonal Balancing Energy Service, Reliability Must-Run (RMR) Service, Out of Merit Capacity (OOMC) Service, Replacement Reserve Service (RPRS), Out of Merit Energy (OOME) Service, or Resource-specific Dispatch Instructions used to resolve Congestion on that particular transmission path in that particular direction during the prior year. Candidate CSCs may also be identified by considering projected annual Congestion costs for the CSC designation year. Since this type of data reflects past system topology and generation, generation and transmission system changes expected to be in service in the CSC designation year shall also be considered.

(iii) Candidate CSCs may also be identified based on ERCOT's operational experience.

(b) If no new candidate CSCs are considered other than the immediately preceding year's CSCs, then ERCOT shall use the Congestion Zones from the immediately preceding year as Study Zones.

(c) If new candidate CSCs are considered, then ERCOT shall calculate Shift Factors and perform cluster analysis based on the candidate CSCs to create Study Zones.

(d) ERCOT shall perform system simulation studies with transfers between the Study Zones and find constraints on the transmission system to determine if candidate CSCs are appropriate for designation as CSCs.

(e) ERCOT shall recommend whether the candidate CSCs qualify for CSC designation. The following factors shall be considered:

(i) Whether there is a sufficiently competitive market to resolve Congestion on the transmission path to be considered for CSC designation. One factor that will be considered when assessing whether a sufficiently competitive market exists is the concentration of capacity ownership or control by Market Participants or their Affiliates, compared to the distribution of Shift Factor impacts;

(ii) Whether the candidate CSC is an adequate indicator to be used to operationally manage and measure inter-zonal transfers; and

(iii) Whether deployment of zonal balancing will be effective for managing the post-contingency flow on the limiting element.

(2) ERCOT shall present all candidate CSCs and proposed Congestion Zones to the appropriate TAC subcommittee. ERCOT shall identify the candidate CSCs and proposed Congestion Zones it believes are the most appropriate CSCs and proposed Congestion Zones and shall explain the basis for its position. ERCOT's justification shall include any operational or reliability concerns that it has identified with any candidate CSCs and proposed Congestion Zones.

(3) CSC approval process: The appropriate TAC subcommittee will review the results and the process followed above to determine the list of constraints to be recommended for approval to the TAC. TAC shall then make a recommendation to the ERCOT Board.

7.2.2 Congestion Zone & Zonal Shift Factor Determination Methodology

ERCOT will take the following steps to determine Congestion Zones and Zonal Shift Factors:

(1) Shift Factors are developed using a linearized (Direct Current (DC)) model to identify the impact of each transmission bus on each CSC relative to an ERCOT reference bus.

(2) A statistical clustering analysis will be used to aggregate transmission buses into zones based upon similar Shift Factors relative to all CSCs. The clustering must meet the

following criteria: (i) each CSC must straddle a zonal boundary (however, not every zonal boundary need be straddled by a CSC); and (ii) station IDs as provided by Transmission and/or Distribution Service Providers (TDSPs) in Section 15.1.1.5, Response from TDSP to Registration Notification Request, can be assigned only into one (1) Congestion Zone.

The following measurements will be calculated for each combination of zones: (i) the maximum difference between the Zonal Shift Factor and the Shift Factor of any generation bus within the zone; and (ii) the R^2 (coefficient of determination) from the cluster analysis.

The system model used to conduct the clustering analysis required by this Section shall be either a pre-contingency or post-contingency system model. A pre-contingency system representation in the model shall be used when the candidate CSC is the contingency element or a stability interface limit. A post-contingency system representation in the model shall be used when the candidate CSC is the limiting element.

(3) If the clustering process described in paragraph (2) above, results in the splitting of two (2) or more buses within any single station into different zones, then the following process will be used to adjust the zone selection to place all buses within a single station in the same zone:

(a) For Generation Resource stations, determine which zone contains the largest amount of generating capacity of the station and assign all buses of that station to that zone;

(b) For all other stations, determine which zone is assigned the largest total amount of Customer Load of the buses in the station and assign all buses of that station to that zone;

(c) If there is no Load or generation in the station, or if the amount of generation and/or Load assigned to individual station buses are equal, then the Load or generation shall be assigned to the zone containing the lowest bus number of the station.

(4) Zonal Shift Factors for each CSC will be determined by averaging the individual bus Shift Factors within each Congestion Zone for the corresponding CSC, weighted by the megawatt levels on the bus in the Load flow base case used to determine CSC Limits from Generation Resources deemed likely to vary their output.

The appropriate TAC subcommittee will review the results and the process followed above to determine the Congestion Zones to be recommended for approval to the TAC. TAC shall then make a recommendation to the ERCOT Board.

(5) Thirty (30) days prior to TAC review, a Non Opt-In Entity (NOIE) may request an exemption to its zonal placement by submitting a request to ERCOT for consideration. ERCOT will evaluate the merits of the request and authorize the exemption based on the following criteria:

(a) Exemptions shall not cause significant operational impact to the ERCOT System. This will normally be satisfied if the request will not result in a change in the annual average Shift Factor for the original or requested Congestion Zone by more than five-percent (5%). After the proposed move, the Zonal Shift Factor in each of the original and requested Congestion Zones shall be no less than ninety-five percent (95%), and no more than one hundred and five percent (105%), of its original Zonal Shift Factor before the proposed move.

Because only buses with generation have an impact on the calculation of Zonal Shift Factors, if no generation exists at a bus that is part of an exemption request, a token generator of one (1) MW will be placed at that bus to test the impact of moving that bus from one zone to another. This will be done to all buses that make up a request for exemption. For example, if an Entity is requesting an exemption for five (5) buses and only one (1) bus has generation On-line in the Load flow case used to test the impact, one (1) MW of generation will be placed at the four (4) other buses and the impact of all five (5) buses on Zonal Shift Factors will be determined as a group as opposed to individually. The Load flow case used to determine this impact will be the same Load flow case used to calculate annual Transmission Congestion Right (TCR) quantities.

(b) Exemptions shall not have a commercial impact/gain for the requestor. This will be measured by whether or not the scheduling which would otherwise result would be eligible for Pre-assigned Congestion Rights (PCRs).

7.2.3 Determining Closely Related Elements (CREs)

ERCOT shall evaluate each contingency element/limiting element pair (constraint) combination to determine if deployment of zonal Balancing Energy will be effective for managing the post-contingency flow on the limiting element. Based on this evaluation, ERCOT shall develop proposed CREs and a list of contingencies for managing CSC and CRE related Congestion. ERCOT shall present all proposed CREs and a list of contingencies for managing CSC and CRE related Congestion, including justification for their inclusion, to the appropriate ERCOT TAC subcommittee for approval. For each year, ERCOT shall identify potential CREs using the following process:

(1) Using the same Load flow data and flow limits used to determine CSCs, determine the transfer capability between Congestion Zones that are Terminal Zones for CSCs. “Terminal Zones” means the pair of zones containing the endpoints of the CSC for which a particular candidate CRE is proposed.

(2) Identify contingency/limiting element pairs that are binding for transfers between zones for up to one hundred fifty percent (150%) of the transfer capability identified in paragraph (1) above.

(3) The limiting elements that meet the CRE criteria below for all contingency/limiting pair elements may be submitted to TAC for approval.

ERCOT may propose additional CREs as provided under this Section, provided the results of the tests below are submitted as well as a description of a need for the CRE. If a proposed CRE fails any of the tests below, ERCOT shall provide an explanation of the reason ERCOT believes the proposed element should nevertheless be designated a CRE.

7.2.3.1 CRE Criteria

Each of the following criteria will use the post-contingency generation Shift Factors of the candidate contingency/limiting element pairs. In order for a CRE to pass, all constraints identified in Section 7.2.3, Determining Closely Related Elements (CREs), associated with the CRE should pass the tests below.

7.2.3.1.1 Power Transfer Distribution Factor (PTDF) Threshold

(1) The Power Transfer Distribution Factor (PTDF) measures the impact of power flow between a pair of locations on a particular transmission element.

(2) "Terminal Zones" means the pair of zones containing the endpoints of the CSC for which a particular candidate CRE is proposed.

(3) Determine the weighted average PTDF between the Terminal Zones of the candidate CRE by calculating the Shift Factor difference between the source and sink zones. The weighted averages will only consider generation technologies that would be responsive to price signals. For the source zone, the technologies excluded are:

(a) Cogeneration;

(b) Nuclear;

(c) Hydro; and

(d) DC Ties.

For the sink zone, the technologies excluded are:

(a) Wind;

(b) Cogeneration;

(c) Nuclear;

(d) Hydro;

(e) Coal; and

(f) DC Ties.

(4) In order for the limiting element of the contingency limiting element pair to qualify as a CRE, the weighted average PTDF between the Terminal Zones for that element should be greater than 0.05, and the ratio of the PTDF to the line rating of the limiting element shall be greater than 0.0002 (e.g., the threshold PTDF for a line rated at 250 MVA is 250 * 0.0002 or 0.05). However, if the weighted average PTDF between the Terminal Zones for the candidate CRE is greater than 0.2, then the candidate CRE would satisfy this criterion.

7.2.3.1.2 Generation Concentration

ERCOT shall determine the concentration of effective generation responsive to the constraint on both the incremental and decremental sides of the constraint.

(1) Calculate the PTDF of all generators as the Shift Factor of the generator relative to the proposed CRE minus the generation weighted average Shift Factor of each CSC Terminal Zone relative to the proposed CRE. For example, for a CRE candidate for the West to North CSC, the PTDFs on the CRE of all generators would be calculated relative to the North Zone for the decremental side of the CRE, and the PTDFs on the CRE of all generators would be calculated relative to the West Zone for the incremental side of the CRE.

(2) For movable generation capacity (in any zone) equal to twice the CRE rating and having the greatest impact on the CRE on incremental side, calculate their generation weighted average PTDF with respect to the decremental Terminal Zone of the CSC. This calculation is done by sorting the moveable generation capacity list from greatest to least absolute value PTDF on the CRE, summing the moveable capacity down to the first generator where the sum of the moveable capacity is just greater than twice the rating of the proposed CRE, and then calculating the generation weighted average PTDF for that amount of moveable capacity with respect to the decremental Terminal Zone of the CSC. In the example above, the decremental zone is the West Zone.

(3) For movable generation capacity (in any zone) equal to twice the CRE rating (using the same flow limits as for TCR modeling) and having the greatest impact on the CRE on decremental side, calculate their generation weighted average PTDF with respect to the incremental Terminal Zone of the CSC. This calculation is done by sorting the moveable generation capacity list from greatest to least absolute value PTDF on the CRE, summing the moveable capacity down to the first generator where the sum of the moveable capacity is just greater than twice the rating of the proposed CRE, and then calculating the generation weighted average PTDF for that amount of moveable capacity with respect to the incremental Terminal Zone of the CSC. In the example above, the incremental zone is the North Zone.

(4) In order for the limiting element of the contingency limiting element pair to qualify as a CRE, incremental movable generation capacity equal to twice the CRE's rating should not have a generation weighted average PTDF on the CRE greater than twice the zonal average PTDF on the CRE of the incremental Terminal Zone of the CSC. Similarly,

decremental movable generation capacity equal to twice the CRE's rating should not have a generation weighted average PTDF on the CRE greater than twice the zonal average PTDF on the CRE of the decremental Terminal Zone of the CSC.

7.2.3.1.3 Boundary Generation Resources

ERCOT shall determine the impact error due to Boundary Generation Resources as follows:

(1) For each generator, find the generator's PTDF on the CRE to each Congestion Zone and select the Congestion Zone to which the generator's PTDF on the CRE has the lowest absolute value;

(2) If the Congestion Zone selected in paragraph (1) above is different from the generator's designated Congestion Zone, then that generator is a Boundary Generation Resource;

(3) Determine the impact error of a Boundary Generation Resource by multiplying the difference between the absolute value of the generator's PTDF on the CRE to its designated Congestion Zone minus the absolute value of the generator's PTDF on the CRE to the Congestion Zone selected in paragraph (1) above times its maximum capacity.

In order for the limiting element of the contingency-limiting element pair to qualify as a CRE, the sum of the impact errors of all Boundary Generation Resources should be less than or equal to thirty percent (30%) of the rating of the CRE (using the same flow limits as for TCR modeling).

7.2.3.1.4 CRE Correlation to CSC

ERCOT shall determine the correlation of the CRE to its designated CSC by calculating the percentage error in deployment as follows:

(1) For the CRE and its CSC, determine their PTDFs for each pair of Congestion Zones using the method described in paragraph (3) of Section 7.2.3.1.1, Power Transfer Distribution Factor (PTDF) Threshold.

(2) Calculate a scaling factor "A" by dividing the CSC PTDF for the CSC's Terminal Zones by the CRE PTDF for the CSC's Terminal Zones, i.e., A = (CSC PTDF)/(CRE PTDF), both PTDFs being for the CSC Terminal Zones.

(3) Determine the error in deployment for each pair of Congestion Zones, B_p, by subtracting the product of A times the CRE PTDF from the CSC PTDF for the same pair of Congestion Zone, i.e. $B_p = (\text{CSC PTDF})_p - A^*(\text{CRE PTDF})_p$, where p is one pair of Congestion Zones.

(4) Determine the percentage error in deployment by dividing B_p by the CSC PTDF for the CSC's Terminal Zones.

In order for the limiting element of the contingency limiting element pair to qualify as a CRE, the maximum absolute value of percentage error of deployment should be less than fifty percent (50%).

7.2.3.1.5 Intra-Year CRE Recommendation and Approval

During the effective year, ERCOT may propose modifications to the list of CREs or the approved list of contingencies for managing CSC and CRE related congestion, including the expected duration of those modifications, as needed to more closely represent actual system constraints that can be effectively resolved by zonal Balancing Energy deployments. Any modifications to the list of CREs or the approved list of contingencies for managing CSC and CRE related congestion will not affect Congestion Zone definition or composition, nor will they affect CSC definitions. ERCOT shall present modifications proposed to the list of CREs or the approved list of contingencies for managing CSC and CRE related Congestion after the start of the year to TAC for approval. TAC will have seven (7) days to take action on the proposed modification. If TAC takes no action within seven (7) days, the proposed modification shall be deemed approved.

7.2.4 Determining Generation Resources Deemed Likely to Vary Their Output

At the beginning of each year, ERCOT will compile a list of all Generation Resources fueled by nuclear fuel, coal or lignite. ERCOT will exclude such units from the calculation of Zonal Shift Factors for the rest of the year. All other Generation Resources will be deemed likely to vary their output.

7.3 Congestion Management for CSCs/Zonal Congestion

7.3.1 Determination of Zonal Congestion

ERCOT will analyze energy schedules to determine the existence and extent of Zonal Congestion as part of the Day Ahead Scheduling Process.

7.3.2 Resolution of Zonal Congestion

ERCOT will resolve Zonal Congestion by the following means:

(1) Using adjusted Balanced Schedules received from Qualified Scheduling Entities (QSEs) after ERCOT's posting of Commercially Significant Contraints (CSC) impacts greater than the CSC Limit, ERCOT will reassess the resulting level of Zonal Congestion. ERCOT will take no further Zonal Congestion actions if the adjusted Balanced Schedules resolve initial Zonal Congestion.

(2) If Zonal Congestion still exists following receipt of adjusted Balanced Schedules, ERCOT may procure Replacement Reserve Service (RPRS) in accordance with Section

6.6.3.2, ERCOT Ancillary Services Procurement during Adjustment Period (AP), provided that sufficient Resources are available to provide Balancing Energy in the Operating Period, in accordance with Section 6.6.3.2. ERCOT will then balance the energy within the ERCOT System in the Operating Period respecting all operational limitations of the ERCOT System.

(3) Zonal Balancing Energy can be deployed only for Congestion management purposes to resolve flow limit violations on CSCs and Closely Related Elements (CREs) where the base case or post-contingency limiting element is the CSC or CRE, unless an Emergency Condition is declared by ERCOT. ERCOT must manage CSC and CRE related Congestion using the approved list of contingencies for managing CSC and CRE related Congestion.

(4) Congestion is resolved in Real Time as follows:

(a) Using Zonal Shift Factors, estimate zonal Balancing Energy Service deployments needed to maintain flows within CSC Limits. If ERCOT applies any offsets to the zonal Balancing Energy Service deployments based on its operational judgment and experience, it will post a report on the Market Information System (MIS) listing the adjustment in MW, by zone, for each interval.

(b) Based on item (4)(a) above, deploy unit specific instructions to manage Local Congestion. The Resource specific instructions will be defined as instructed deviations using the following criteria:

(i) When a Resource is instructed to operate at or above an instructed output level and the Resource Plan output level is below the instructed output level, the instructed deviation will be defined as the difference between the instructed output level and Resource Plan output level for the target interval.

(ii) When a Resource is instructed to operate at or below an instructed output level and Resource Plan output level is above the instructed output level, the instructed deviation will be defined as the difference between the instructed output level and Resource Plan output level for the target interval.

(iii) When a Resource is requested to go to an instructed output level, the instructed deviation will be defined as the difference between the instructed output level and the Resource Plan output level.

(iv) Otherwise, the Resource specific deployment will not be defined as instructed deviation.

(c) Clear the Balancing Energy Service market to maintain system power balance and the CSC flow within the CSC Limit.

(d) In the event of a contingency, estimate Balancing Energy Service deployment to maintain flows within pre-second contingency CSC Limits and deploy unit-specific instructions to manage any resulting Local Congestion and clear the Balancing Energy Service market to maintain CSC flows within pre-second contingency CSC Limits.

(5) The Shift Factors for CSCs and CREs shall be at the same value.

The result of Congestion Management should ensure that:

(1) Balancing Energy Market Clearing Prices for Energy (MCPEs) are the same in all zones if no CSC or CRE is constrained.

(2) Balancing Energy MCPEs will be different in two (2) or more Congestion Zones only if one (1) or more CSCs/CREs are constrained.

(3) The Shadow Price of a constrained CSC will be calculated by taking the difference in Balancing Energy MCPEs between any two (2) zones divided by the difference in Zonal Shift Factors on the corresponding CSC of the two (2) zones even in the event of an Outage of the CSC. If there is no feasible solution, then these criteria may not be met.

7.3.3 [Expired 2/15/2002]

7.3.3.1 [Expired 2/15/2002]

7.3.3.2 [Expired 2/15/2002]

7.3.3.3 [Expired 2/15/2002]

7.3.3.3.1 [Expired 2/15/2002]

7.3.4 Settlement of Zonal Congestion

7.3.4.1 Balancing Energy CSC Congestion Charge

The calculation for Zonal Congestion Management Charge is as follows:

$$\mathbf{I_{CSCiq} = \Sigma\, ((QSS_{iqz} - SO_{iqz}) * SF_{zcsc})_z}$$

If $\mathbf{I_{CSCiq} > 0}$ then,

$$\mathbf{CSC_{BECSCiq} = SP_{CSCi} * MAX\,(0,\, I_{CSCiq})}$$

Else (counterflow)

$$\mathbf{CSC_{BECSCiq} = SP_{CSCi} * I_{CSCiq}}$$

End

$$CSC_{BEiq} = SUM\ (CSC_{BECSCiq})_{CSC}$$

i	Interval being calculated
q	QSE
z	Congestion Zone
CSC	Commercially Significant Constraint
$CSC_{BECSCiq}$	CSC Energy Related Congestion Charge, per interval, per CSC, per QSE
CSC_{BEiq}	CSC Energy Related Congestion Charge, per interval of that QSE
SP_{CSCi}	Shadow Price per CSC, per interval
I_{CSCiq}	Scheduled MW Impact per CSC, per interval, per QSE
SF_{zcsc}	Commercial Model Shift Factor of Generation Resources deemed likely to vary their output per CSC, per zone
QSS_{iqz}	QSE Supply Schedule per interval, per zone, per QSE
SO_{iqz}	Scheduled Obligation (prior to Real Time) per interval, per zone, per QSE

ERCOT will compute the Zonal Shift Factors for settlement purposes using Shift Factors of Generation Resources within the zone deemed likely to vary their output, weighted by the generation level in the monthly base case. The monthly base case will be the most recent base case used by ERCOT but no less current than the base case used by ERCOT to determine the number of TCRs available for sale for the corresponding month.

7.3.4.2 Replacement Reserve Service Zonal Congestion Charge

Replacement Reserve Zonal Congestion costs will be allocated directly to the QSE impacting the CSC. The Replacement Reserve Zonal Congestion costs per interval per QSE will be determined by multiplying the Shadow Price of CSC capacity by the QSE's CSC impact and in that interval.

The CSC impact is determined by taking for each Congestion Zone, the maximum difference, in any of the four intervals in an hour, between each QSE's Supply schedules and the QSE Obligation schedules at the time of each round of Replacement Reserve capacity procurement multiplied by the Zonal Shift Factor. The calculation of the Replacement Reserve Service Zonal Congestion Charge will be as follows:

$$\mathbf{CSC_{RPhq} = SPC_{CSCh} * MAX\ (0, I_{CSChq}))}$$

$$\mathbf{I_{CSChq} = MAX\ \left[0, MAX\ \left[\Sigma\ ((QSS_{TOPiqz} - QOS_{TOPiqz}) * SF_{zcsc})_z\right]_n\right]}$$

Where:

h	hour being calculated
i	interval within hour h

n	The number of times that RPRS is procured.
q	QSE
z	Congestion Zone
CSC	Commercially Significant Constraint
CSC_{RPiq}	CSC Replacement Reserve related Congestion charge, per interval, per QSE
SPC_{CSCi}	Capacity Shadow Price per CSC, per interval
I_{CSCiq}	Scheduled MW Impact per CSC, per interval, at the time of purchase, per QSE
SF_{zcsc}	Zonal Shift Factor per CSC, per zone
QSS_{TOPiqz}	QSE Supply Schedule per interval, per zone, at the time of purchase, per QSE
QOS_{TOPiqz}	QSE Obligation Schedule per interval, per zone, at the time of purchase, per QSE

7.4 Congestion Management for Local Congestion

7.4.1 Determination of Local Congestion

ERCOT will use the Operational Model of the ERCOT System in combination with QSE energy schedules and ERCOT forecasted Load to determine the extent of Local Congestion.

When ERCOT identifies Local Congestion on a repeated basis ERCOT shall have procedures established to contact the appropriate TDSP to:

(1) Verify that ratings of Transmission Facilities in the ERCOT Operational Model causing the event are current and correctly represented;

(2) Verify, when the TDSP's analysis results differ from those of ERCOT, that the configuration of the transmission system in the ERCOT Operational Model matches that in use by the TDSP. To recognize operational time constraints, such verification will focus on transmission elements believed to have impacted the event; and

(3) Mutually identify with the TDSP any additional operational intervention or system monitoring that could be implemented to manage recurring Congestion due to a recurring cause.

If it is determined that rating(s) in the ERCOT Operational Model or configuration of the Transmission Facilities are not correct, then the TDSP will provide, via submittal of a Service Request on the ERCOT MIS, written confirmation of the correction. Once written confirmation is completed, ratings in the ERCOT Operational Model will be updated in the Real Time systems by the close of the next Business Day, and such rating changes and any needed configuration changes will be included in the next scheduled Operational Model database update. Once additional operational intervention to the transmission system has been identified (if any) to relieve Congestion and mutually accepted by both ERCOT and TDSP operators, the necessary operational instructions shall be prepared and implemented as soon as practicable.

ERCOT will use an interim practice between the identification of a problem and the final authorized submittal of a Service Request in order to implement corrections as soon as practicable. The interim practice will allow an authorized or alternate contact to provide corrected ratings to ERCOT by email. ERCOT will enter that rating into the Real Time systems to be used in current operating activities on a temporary basis. After the Service Request documentation is received by ERCOT, permanent changes will be made in the Operational Model and loaded into the operating systems.

7.4.2 Resolution of Local Congestion

ERCOT will procure RPRS if necessary to provide sufficient capacity to resolve forecasted Local Congestion. ERCOT will purchase RPRS from the Resource(s) having the lowest cost per megawatt based on each Resource's Resource Category Generic Cost and its ability to resolve the Congestion given its Shift Factor on the Local Congestion.

ERCOT will instruct and Dispatch Resources in Real Time in a manner that does not exceed the units' operational limits known to ERCOT. The Resources that have been instructed to operate within a range to resolve Local Congestion are paid or pay a price, in accordance with Section 7.4.3.1, Balancing Energy Up from a Specific Resource, Section 7.4.3.2, Balancing Energy Down from a Specific Resource, and Section 6.8, Compensation for Services Provided.

The Local Congestion Costs are embedded in each service deployed to resolve Local Congestion such as OOMC, OOME, and unit specific premiums.

The formula to calculate Local Congestion Replacement Reserve payment can be found in Section 6.8.1.11, Local Congestion Replacement Reserve Payment to QSE, of these Protocols.

7.4.3 Settlement of Local Congestion Costs

Net Local Congestion costs will be settled in the Balancing Energy settlement process.

7.4.3.1 Balancing Energy Up from a Specific Resource

(1) In accordance with Section 6.7.1.2, Deployment of Balancing Energy when Congestion Occurs, whenever a specific Resource with a submitted bid premium, in accordance with the Resource Category Generic bid limit for Balancing Energy Up, is deployed incrementally to solve Local Congestion, the QSE will be paid the difference between the MCPE of the Congestion Zone in which the specific Resource is located and the incremental bid premium specified. Aggregated Unit rules as described in Section 6.8.2, Capacity and Energy Payments for Out of Merit Service, apply to Aggregated Units approved by ERCOT.

The calculation of the payment for Balancing Energy Up from a specific Resource is as follows:

$$\mathbf{LPC_{RSUquiz} = -1 * \Sigma\ ((PM_{qiuz} - MCPE_{iz})* Max\ (0, Min\ (MR_{qiuz} - OL_{qiuz}, IOL_{qiuz} - OL_{qiuz})))}$$

$$\mathbf{LPC_{RSUqviz} = -1 * \Sigma\ ((PM_{qivz} - MCPE_{iz})* Max\ (0, Min\ (MR_{qivz} - OL_{qivz}, NETUEQ_{ivq})) * LBEAGR_{ivq})}$$

For gas-fired units:

$FBPM_{qiuz} = (BPM_{qiuz} / FIP_{d-1}) * FIP_d$

$PM_{qiuz} = Max\ (FBPM_{qiuz}, MCPE_{iz})$

$PM_{qivz} = Min(PM_{qiuz})$

For all other Resource categories:

$PM_{qiuz} = Max\ (BPM_{qiuz}, MCPE_{iz})$

$PM_{qivz} = Min(PM_{qiuz})$

$NETUEQ_{ivq} = Max\ [0, ((NETOOMUEQ_{ivq} + NETLBEUQ_{ivq}) - (NETOOMDEQ_{ivq} + NETLBEDQ_{ivq}))]$

$NETOOMUEQ_{ivq} = Max(0, (SUM(I_{OOMUPqui})_u - SUM(I_{OOMDNqui})_u))$

$NETLBEUQ_{ivq} = Max\ (0, (SUM(LBEUQ_{qui})_u - SUM(LBEDQ_{qui})_u))$

$NETOOMDEQ_{ivq} = Max(0, (SUM(I_{OOMDNqui})_u - SUM(I_{OOMUPqui})_u))$

$NETLBEDQ_{ivq} = Max(0, (SUM(LBEDQ_{qui})_u - SUM(LBEUQ_{qui})_u))$

$LBEAGR_{ivq} = [(SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u)] / [SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u + SUM(I_{OOMUPqui})_u + SUM(I_{OOMDNqui})_u]$

Where:

d	Operating Day of interval i
i	interval
q	QSE
u	individual Generation unit (including units within an Aggregated Unit)
v	Aggregated Unit
z	zone
BPM_{qiuz}	Incremental bid premium for that specific unit per interval
$FBPM_{qiuz}$	Incremental bid premium, adjusted for fuel price, for that specific unit per interval
FIP_d	Fuel Index Price for Operating Day of interval i
FIP_{d-1}	Fuel Index Price used to calculate Resource category bid limits effective for Operating Day of interval i
IOL_{qiuz}	The Instructed output level for the unit given the unit-specific instruction
$I_{OOMDNqui}$	OOM Energy Down Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)

$I_{OOMUPqui}$	OOM Energy Up Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
$LPC_{RSUquiz}$	Payment to QSE for providing Balancing Energy Up from a specific unit to solve Local Congestion per QSE per interval per zone
$LPC_{RSUqviz}$	Payment to QSE for providing Balancing Energy Up from Aggregated Units to solve Local Congestion per QSE per interval per zone
$LBEAGR_{ivq}$	The percentage of the aggregated instructions to the Aggregated Unit that represents the OOM Energy market
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions for that interval per specific unit
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions for that interval per specific unit
$MCPE_{iz}$	Market Clearing Price for Energy per interval per zone
MR_{qiuz}	Meter reading per unit per interval
MR_{qivz}	Meter reading per Aggregated Unit per interval
$NETLBEDQ_{ivq}$	The net of all unit specific Local Balancing Energy Instructions (Down minus Up) that result in a positive value
$NETLBEUQ_{ivq}$	The net of all unit specific Local Balancing Energy Instructions (Up minus Down) that result in a positive value
$NETOOMDEQ_{ivq}$	The net of all unit specific OOM instructions (Down minus Up) that result in a positive value
$NETOOMUEQ_{ivq}$	The net of all unit specific OOM instructions (Up minus Down) that result in a positive value
$NETUEQ_{ivq}$	The overall net direction per the instructions given to the Aggregated Unit results in an up direction
OL_{qiuz}	Resource Plan output level submitted by the QSE for the specific unit given the unit-specific instruction for that interval
OL_{qivz}	Resource Plan output level submitted by the QSE for the Aggregated Unit containing the unit given the unit-specific instruction for that interval
PM_{qiuz}	Incremental Premium Specified for that specific unit per interval
PM_{qivz}	Incremental Premium Specified for that specific Aggregated Unit per interval

(a) The Nodal Market implementation requires Early Delivery System (EDS) testing. During the EDS 3 R6.3 Load Frequency Control (LFC) testing as documented by ERCOT's issuance of Dispatch Instructions to perform the test, the formula in Section 7.4.3.1(1) will be modified in the following way:

$$I_{OOMUPiuq} = \frac{1}{4} * \left(\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y})\right)$$

$$I_{OOMDNiuq} = \frac{1}{4} * \left(\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y})\right)$$

$$LBEUQ_{qui} = \frac{1}{4} * \left(\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y})\right)$$

$$LBEDQ_{qui} = \frac{1}{4} * \left(\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y})\right)$$

Where:

$I_{OOMUPiuq}$	OOM Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Up deployment.
$I_{OOMDNiuq}$	OOM Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Down deployment.
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Up deployment.
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Down deployment.
BP_{y}	Base Point by interval - The Base Point generated from SCED test system for the Generation Resource for the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
$TLMP_{y}$	Duration of SCED interval per interval - The duration of the portion of the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
y	A SCED interval in the Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
i	15-minute Settlement Interval.
u	Individual Generation unit (including units within an Aggregated Unit).
q	QSE.

(i) During EDS 3 R6.3 LFC testing, when a combined cycle Resource receives SCED Base Points at the Combined Cycle Configuration (as defined in the ERCOT Nodal Protocols) level, ERCOT will use MW telemetry based splitting percentages to allocate the OOME or Local Balancing Energy Instruction, as calculated in Section 7.4.3.1(1)(a) above, to each individual unit making up the Combined Cycle Configuration for each 15-minute Settlement Interval.

(ii) If, after receiving the Initial Statement for the Operating Day on which EDS 3 R6.3 LFC testing occurred as documented by Dispatch Instruction to the QSE for a specific test period, a QSE does not agree with the updated Instructed Output level or payment for OOME or Local Balancing Energy, a QSE may submit a settlement and billing dispute in accordance with the process outlined in Section 9.5, Settlement and Billing Dispute Process. In addition to the standard information required on the dispute form, the dispute should clearly reference the EDS 3 R6.3 LFC test and indicate the disputed Settlement Intervals involved in the test.

(2) Whenever a LaaR with a submitted bid premium, in accordance with the Resource Category Generic bid limit for Balancing Energy Up, is deployed to solve Local Congestion, the QSE will be paid the incremental premium specified as defined below:

$$\mathbf{LPC_{LAARquiz} = -1 * \Sigma\ ((PM_{qiuz} - MCPE_{iz})* Max\ (0, Min\ (OL_{qiuz} - LAARTOT_{qiuz}, OL_{qiuz} - IOL_{qiuz})))}$$

$$PM_{qiuz} = Max\ (FBPM_{qiuz}, MCPE_{iz})$$

$$FBPM_{qiuz} = (BPM_{qiuz} / FIP_{d-1}) * FIP_d$$

Where:

i	interval
q	QSE
u	individual LAAR unit
z	zone
BPM_{qiuz}	Incremental bid premium for that specific LaaR unit per interval
$FBPM_{qiuz}$	Incremental bid premium, adjusted for fuel price, for that specific unit per interval
FIP_d	Fuel Index Price for Operating Day of interval i
FIP_{d-1}	Fuel Index Price used to calculate Resource category bid limits effective for Operating Day of interval i
IOL_{qiuz}	The Instructed output level for the LaaR unit given the unit-specific instruction
$LAARTOT_{qiuz}$	Actual ESI ID usage per unit per interval
$LPC_{LAARquiz}$	Payment to QSE for providing Balancing Energy Up from specific LaaR unit to solve Local Congestion per QSE per interval per zone
$MCPE_{iz}$	Market Clearing Price for Energy per interval per zone
OL_{qiuz}	Resource Plan output level submitted by the QSE for the specific LaaR unit given the unit-specific instruction for that interval
PM_{qiuz}	Incremental Premium specified for that specific LaaR unit per interval

7.4.3.2 Balancing Energy Down from a Specific Resource

In accordance with Section 6.7.1.2, Deployment of Balancing Energy when Congestion Occurs, whenever a specific Generation Resource with a submitted bid premium, in accordance with the Resource Category Generic bid limit for Balancing Energy Down, is deployed decrementally to solve Local Congestion, the QSE will be paid the difference between the MCPE of the Congestion Zone in which the specific Generation Resource is located, and the decremental bid premium specified.

The calculation of the payment for Balancing Energy Down from a specific Resource is as follows:

$$\mathbf{LPC_{RSDquiz} = -1 * \Sigma(MAX(0,(MCPE_{iz} - PM_{qiuz})) * Max(0, Min(OL_{qiuz} - MR_{qiuz}, OL_{qiuz} - IOL_{qiuz})))_u}$$

$$\mathbf{LPC_{RSDqviz} = -1 * \Sigma(MAX(0,(MCPE_{iz} - PM_{qivz})) * Max(0, Min(OL_{qivz} - MR_{qivz}\ NETDEQ_{ivq})))_v * LBEAGR_{ivq}}$$

For gas-fired units:

$FBPM_{qiuz} = (BPM_{qiuz} / FIP_{d-1}) * FIP_d$

$PM_{qiuz} = FBPM_{qiuz}$

$PM_{qivz} = Max(PM_{qiuz})$

For all other Resource categories:

$PM_{qiuz} = BPM_{qiuz}$

$PM_{qivz} = Max(PM_{qiuz})$

$NETDEQ_{ivq} = Max [0, ((NETOOMDEQ_{ivq} + NETLBEDQ_{ivq}) – (NETOOMUEQ_{ivq} + NETLBEUQ_{ivq}))]$

$NETOOMUEQ_{ivq} = Max [0, (SUM (I_{OOMUPqui})_u – SUM(I_{OOMDNqui})_u)]$

$NETLBEUQ_{ivq} = Max [0, (SUM(LBEUQ_{qui})_u – SUM(LBEDQ_{qui})_u)]$

$NETOOMDEQ_{ivq} = Max [0, (SUM(I_{OOMDNqui})_u – SUM(I_{OOMUPqui})_u)]$

$NETLBEDQ_{ivq} = Max[0, (SUM(LBEDQ_{qui})_u – SUM(LBEUQ_{qui})_u)]$

$LBEAGR_{ivq} = [SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u] / [SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u + SUM(I_{OOMUPqui})_u + SUM(I_{OOMDNqui})_u]$

Where:

d	Operating Day of interval i
i	interval
q	QSE
u	individual Generation unit (including units within an Aggregated Unit)
v	Aggregated Unit
z	zone
BPM_{qiuz}	Decremental bid premium specified for that specific unit per interval
$FBPM_{qiuz}$	Decremental bid premium, adjusted for fuel price, for that specific unit per interval
FIP_d	Fuel Index Price for Operating Day of interval i
FIP_{d-1}	Fuel Index Price used to calculate Resource category bid limits effective for Operating Day of interval i
IOL_{qiuz}	The instructed output level for the unit given a unit-specific instruction
$I_{OOMDNqui}$	OOM Energy Down instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)

$I_{OOMUPqui}$	OOM Energy Up instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
$LBEAGR_{ivq}$	The percentage of the aggregated instructions to the Aggregate Unit that represents the OOM Energy market.
$LBEDQ_{qui}$	Local Balancing Energy Down instructions for that interval per specific unit
$LBEUQ_{qui}$	Local Balancing Energy Up instructions for that interval per specific unit
$LPCRSD_{quiz}$	Payment to QSE for providing Balancing Energy Down from a specific unit to solve Local Congestion per QSE per interval per zone
$LPCRSD_{qviz}$	Payment to QSE for providing Balancing Energy Down from Aggregated Units to solve Local Congestion per QSE per interval per zone
$MCPE_{iz}$	Market Clearing Price of Energy per interval per zone
MR_{qiuz}	Meter reading per unit per interval.
MR_{qivz}	Meter reading per Aggregated Unit per interval.
$NETDEQ_{ivq}$	The overall net direction per the instructions given to the Aggregated Unit results in a down direction
$NETLBEDQ_{ivq}$	The net of all unit specific Local Balancing Energy instructions (Down minus Up) that result in a positive value.
$NETLBEUQ_{ivq}$	The net of all unit specific Local Balancing Energy instructions (Up minus Down) that result in a positive value.
$NETOOMDEQ_{ivq}$	The net of all unit specific OOM instructions (Down minus Up) that result in a positive value.
$NETOOMUEQ_{ivq}$	The net of all unit specific OOM instructions (Up minus Down) that result in a positive value.
OL_{qiuz}	Resource Plan output level submitted by the QSE for the unit given the unit-specific instruction for that interval
OL_{qivz}	Resource Plan output level submitted by the QSE for the Aggregated Unit containing the unit given the unit-specific instruction for that interval
PM_{qiuz}	Decremental Premium for that specific unit per interval
PM_{qivz}	Decremental Premium for that specific Aggregated Unit per interval

(a) The Nodal Market implementation requires Early Delivery System (EDS) testing. During the EDS 3 R6.3 Load Frequency Control (LFC) testing documented by Dispatch Instruction to the QSE for a specific test period, the formula in Section 7.4.3.2 will be modified in the following way:

$$I_{OOMUPiuq} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$I_{OOMDNiuq} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEUQ_{qui} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEDQ_{qui} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

Where:

$I_{OOMUPiuq}$	OOM Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Up deployment.
$I_{OOMDNiuq}$	OOM Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Down deployment.
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Up deployment.
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Down deployment.
BP_{y}	Base Point by interval - The Base Point generated from SCED test system for the Generation Resource for the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
$TLMP_{y}$	Duration of SCED interval per interval - The duration of the portion of the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
y	A SCED interval in the Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
i	15-minute Settlement Interval.
u	Individual Generation unit (including units within an Aggregated Unit).
q	QSE.

(i) During EDS 3 R6.3 LFC testing, when a combined cycle plant receives SCED Base Points at the Combined Cycle Configuration (as defined in the ERCOT Nodal Protocols) level, ERCOT will use MW telemetry based splitting percentages to allocate the OOME or Local Balancing Energy Instructions, as calculated in Section 7.4.3.2(1)(a) above, to each individual unit making up the Combined Cycle Configuration for each 15-minute Settlement Interval.

(ii) If, after receiving the Initial Statement for the Operating Day on which EDS 3 R6.3 LFC testing occurred as documented by Dispatch Instruction(s) to the QSE for a specific test period, a QSE does not agree with the updated Instructed Output level or payment for OOME or Local Balancing Energy, a QSE may submit a settlement and billing dispute in accordance with the process outlined in Section 9.5, Settlement and Billing Dispute Process. In addition to the standard information required on the dispute form, the dispute should clearly reference the EDS 3 R6.3 LFC test and indicate the disputed Settlement Intervals involved in the test.

7.4.3.3 Balancing Energy Charge to Solve Local Congestion

In accordance with this section, all the cost associated with Balancing Energy from a specific Resource to solve Local Congestion will be allocated on a QSE Load Ratio Share.

$$\mathbf{LCC_{iq} = -1 * \Sigma\ ((LPC_{RSUqiz} + LPC_{RSDqiz}) * LRS_{iq})}$$

Where:

LPC_{RSUqiz}	Payment to QSE for providing Balancing Energy Up from specific Resource to solve Local Congestion per QSE per interval per zone
LPC_{RSDqiz}	Payment to QSE for providing Balancing Energy Down from specific Resource to solve Local Congestion per QSE per interval per zone
LCC_{iq}	Local Congestion Load allocation charge per QSE per interval
LRS_{qi}	Load Ratio Share

7.4.4 Direct Assignment of Local Congestion Costs

ERCOT shall directly assign Local Congestion costs beginning six months after ERCOT's incurred costs of clearing Local Congestion during a rolling twelve month period reaches 20 million dollars.

[PRR492 & PRR532: Add Section 7.4.5 upon system implementation and filling staffing requirements:]

7.4.5 Plan to Alleviate Chronic Local Congestion Charges

(1) ERCOT shall monitor Local Congestion Area costs and post a report on the MIS ten (10) days following the end of the month. The report shall include the amount of Local Congestion Area costs by type of payment to Resources (e.g., OOME Up, OOME Down, and OOMC) including discussion of the limiting transmission element(s) or other significant events that may have contributed to Local Congestion as available. This information will also be reported monthly to the ERCOT Board of Directors, PUCT Market Oversight Division, and appropriate ERCOT subcommittees.

(2) For the purposes of this section, "Local Congestion Area" is defined as a sub-region of a Congestion Zone in which ERCOT dispatches OOME, OOMC, or local Balancing Energy Service on a regular basis as described in the ERCOT monthly report of Local Congestion Cost.

(3) If the amount of OOME, OOMC, or local Balancing Energy Service in a Local Congestion Area exceeds a threshold amount of either ten million dollars ($10 million) during the most current twelve (12) consecutive months or five million dollars ($5 million) in the most current three (3) consecutive months, ERCOT shall report such to

the ERCOT Board, PUC Market Oversight Division, and appropriate ERCOT subcommittees and shall initiate a study to identify feasible alternatives that may, at a future time, be more economically efficient than the continued use of OOME, OOMC, or local Balancing Energy Service.

(4) ERCOT shall develop feasible alternatives and their associated costs to reduce or replace the use of OOME, OOMC, or local Balancing Energy Service. At a minimum, the list of feasible alternatives that ERCOT shall include consideration of a new CSC for the following year under Section 7.2.1.1, Process for Determining CSCs, item (2), a change in ERCOT operations affecting the Local Congestion, construction of new or expansion of existing Transmission Facilities, installation of voltage control devices, more accurate modeling of transmission line or transformer MVA Real Time limits, solicitation or auctions for interruptible Load from Load Serving Entities when such Protocols are available, or continued use of OOME, OOMC, or local Balancing Energy Service.

(5) ERCOT shall prepare a report, no later than forty-five (45) days after the threshold is exceeded, on the feasible alternatives available to reduce Local Congestion below the threshold amount. The report shall include:

(a) The root cause of the Local Congestion;

(b) Current actions of the TDSP and/or ERCOT to relieve such Local Congestion;

(c) A review of ERCOT's operations (e.g., Dispatch Instructions, transmission line limits, etc.);

(d) A determination of short term mitigation measures that could reduce the use of OOME, OOMC or local Balancing Energy Service; and

(e) The amount of market impact caused by the Local Congestion.

The report shall also include an implementation plan, timeline, and recommendations regarding short-and long-term solutions to the Local Congestion as appropriate. The implementation plan may identify studies to be conducted prior to recommendations for short- and long-term solutions to the Local Congestion. These additional studies will be conducted through the regional planning process, as appropriate.

(6) This report shall be posted on the MIS and provided to the PUCT Market Oversight Division, the appropriate ERCOT subcommittee(s), and ERCOT Board of Directors.

(7) Subsequent to the initial report, ERCOT staff shall provide monthly updates on the schedule and planning status to the PUCT Market Oversight Division, appropriate ERCOT subcommittee(s), and the Board. ERCOT will use its best efforts to implement short- and long-term solutions as quickly as practical.

7.5 Transmission Congestion Rights

Pre-assigned Congestion Rights (PCRs) are priced differently than Transmission Congestion Rights (TCRs), and PCRs are allocated rather than awarded as a result of the annual TCR auction process. The eligibility, pricing and annual allocation of PCRs are addressed in Section 7.5.6, Direct Allocation of Pre-assigned Congestion Rights. For all other purposes, PCRs are functionally and financially equivalent to TCRs.

7.5.1 Function of Transmission Congestion Rights

TCRs and PCRs function as financial hedges (similar to financial options with zero strike price) against the marginal costs to resolve Zonal Congestion. The total costs of Zonal Congestion comprise those portions of Replacement Reserve Service (RPRS) costs and the Balancing Energy service costs associated with managing Zonal Congestion. The TCR and PCR holder will receive an amount equal to the directly assigned Congestion costs for an equivalent quantity of scheduled flow. TCRs are not deratable once they are sold in the auction(s), and allocated PCRs are not deratable.

A TCR is a financial right on a specified directional Commercially Significant Constraint (CSC) for a particular hour that entitles the holder of record to receive remuneration equal to the sum of non-negative Balancing Energy service and RPRS Shadow Prices ($/MW/15-minute) over all 15-minute intervals within the hour for the corresponding CSC multiplied by 1 MW.

7.5.2 Procedure for Computation of Transmission Congestion Rights Quantities

The ERCOT System will be modeled and the CSC interfaces determined in accordance with Section 7.2, CSC Zone Determination Process, using steady-state and dynamic power system simulation software. The capacity of the CSCs will be fully used and there will be no reservation of capacity for any particular segment of Load.

ERCOT will determine CSC Limits as follows:

(1) Determine the pre-contingency flow limit on the directional CSC that results in the CSC or any directional Clostely Related Element (CRE) corresponding to the CSC becoming the base case limiting element, for all Congestion Zone-to-Congestion Zone transfer studies.

(2) Determine the pre-contingency flow limit on the directional CSC to withstand any single contingency that results in any directional CRE, including elements comprising the CSC, corresponding to the CSC to become the post-contingency limiting element for all Congestion Zone-to-Congestion Zone transfer studies.

(3) The lower of the CSC flow limits from (1) and (2) above sets the CSC Limit.

7.5.2.1 Annual TCR Quantities

Annually determined Summer ERCOT peak flow limits for CSCs will provide the starting basis for determining the number of TCRs to be auctioned. The flow limit established for each CSC on an annual basis may vary from time to time based on changes in system conditions. The ultimate number of TCRs to be auctioned for the CSCs will take into account forecasted changes in system conditions.

ERCOT will determine the total annual quantity of TCRs for the annual distribution by adjusting the annual summer peak base case CSC Limits by the following amount for each CSC: the sum over all nodes of the product of the expected level of Load at each node from the annual summer peak base case multiplied by the difference between the corresponding Shift Factor for that node and CSC and a modification of the Zonal Shift Factor calculated using all Generation Resources.

7.5.2.2 Monthly TCR Quantities

ERCOT will determine the total quantity of TCRs for the monthly distribution by adjusting the corresponding modified seasonal base case CSC Limits by the following amount for each CSC: the sum over all nodes of the product of the expected level of Load at each node from the modified seasonal base case multiplied by the difference between the corresponding Shift Factor for that node and CSC and a modification of the Zonal Shift Factor calculated using all Generation Resources. The modified seasonal base case for a particular month will be based on the most limiting situation within the corresponding month. This analysis takes into account all transmission outages of significant duration and impact with the objective of collecting sufficient revenues from direct assigned Congestion costs to pay all TCR holders.

ERCOT may distribute TCRs in amounts less than the total quantities based on expectations of the frequency and magnitude of potential CSC de-rates that could occur during any particular month.

7.5.2.3 ERCOT Posting of TCR Quantities

Upon review and approval of the TCR amount, ERCOT will determine and post on the Market Information System (MIS) the total quantity, the amount of PCRs, and the remaining available quantity of TCRs for each CSC. The remaining available quantity of TCRs for auction will be the total amount of TCRs less the amount of PCRs.

7.5.3 Annual and Monthly Auction of Transmission Congestion Rights

7.5.3.1 Annual and Monthly Auction Summary

Forty percent (40%) of the total annual quantity of TCRs less PCRs for any given CSC will be awarded to Market Participants based on the results of an initial annual auction. These TCRs will be made available in the annual auction for each hour of the year. For the annual auction, the quantity of TCRs used to calculate the twenty-five percent (25%) limit, pursuant to Section 7.5.9, Limitation on Ownership or Control of TCRs, is based on the total annual quantity of TCRs (which includes PCRs). Each annual auction will be completed no later than the 15th of December, on a date set by ERCOT.

Prior to each monthly auction, ERCOT will determine the total monthly quantity of TCRs available for that month based upon forecasted system conditions for the month. The amount of TCRs that will be auctioned in the monthly auction will be the total monthly quantity of TCRs, less any PCRs, and less any TCRs for that month sold in the annual auction. For that monthly auction, the quantity of TCRs used to calculate the twenty-five percent (25%) limit, pursuant to Section 7.5.9, is the greater of (A) the total annual quantity of TCRs, or (B) the total monthly quantity of TCRs. However, in determining the amount of TCRs available in each monthly auction, ERCOT shall seek to achieve monthly revenue neutrality to avoid a revenue shortfall due to payment to TCR holders for the month. In an effort to achieve revenue neutrality, ERCOT shall manually adjust the quantity of monthly TCRs auctioned. The manual adjustment made by ERCOT shall not exceed forty-percent (40%) of the Total Transfer Capability of each CSC for the month. In developing the monthly TCR auction model CSC transfer capability, ERCOT shall strive to achieve monthly TCR revenue neutrality. Monthly TCR revenue neutrality is achieved by ensuring that the number of TCRs sold for each CSC is not greater than the average actual Real Time flow capability of that CSC for the month. ERCOT shall strive to ensure that monthly TCR payouts for each CSC, match as closely as possible, total CSC charges for the month for that CSC. Monthly revenue neutrality does not include annual TCR auction revenues.

To achieve this objective, ERCOT may use manual adjustments and/or a scaling factor. In developing these adjustments or scaling factors, ERCOT may consider:

(1) Combinations of Outages known at the time of development of the monthly TCR auction model;

(2) Outages expected to be entered for the month, subsequent to the development of the TCR auction model; and

(3) Historical CSC operational flow capability for the month or Season.

In no event shall ERCOT sell more TCRs than the calculations show to be available. ERCOT shall report the Outages included in the TCR case and the scaling factor(s) and the data used as the basis for developing the scaling factor(s) with the monthly TCR auction announcement.

The TCRs auctioned in the monthly auction will be awarded to Market Participants based on the results of monthly auctions. These TCRs will be made available in the monthly auction for all hours of each day of each month for which the auction is being held. Each monthly auction will be completed no later than the 15th of each month prior to the month that the TCRs are effective, on a date set by ERCOT.

7.5.3.2 Auction Procedures

ERCOT will develop a procedure for authenticating ownership for each TCR.

ERCOT, or its designee, will conduct a single-round, simultaneous combinatorial auction for selling the TCRs available for each annual or monthly auction for all CSCs. ERCOT shall use a standard linear programming model to maximize the auction revenue subject to the constraints that ERCOT and the bidders provide prior to the start of the auction. The clearing-price for each TCR will be equal to the corresponding Shadow Price of the marginal TCR awarded on that CSC.

The auction process will be open to any qualified TCR Account Holder. To participate in the auctions, a bidder must meet financial security requirements established by ERCOT and must have access to the computer hardware, software and communications equipment required to participate.

7.5.3.2.1 TCR Auction Notices

No less than twenty-days (20) prior to the annual auction and ten (10) days prior to the monthly auction, ERCOT will post:

(1) The Zonal Shift Factor and zone-to-zone impact matrix (to determine the megawatt impact on each CSC);

(2) The number of TCRs to be issued for each period (annual, monthly) in that auction;

(3) The number of PCRs that have been allocated for each CSC;

(4) Deadline for bidders to satisfy financial requirements;

(5) Specifications for the equipment necessary to participate in the auction;

(6) The date and time by which bids must be submitted;

(7) The bid format;

(8) CSCs and CREs;

(9) Any other information of commercial significance to bidders; and

(10) The total number of TCRs available and used to determine the 25% limit, pursuant to Section 7.5.9, Limitation on Ownership or Control of TCRs.

7.5.3.2.2 Auction

The auction will be a single-round, simultaneous combinatorial auction for selling the TCRs available for an annual or monthly auction for CSCs, with the following steps:

(1) The following constraints shall be entered into ERCOT's auction engine model:

(a) The maximum number of TCRs for any given CSC available for auction.

(b) The maximum number of TCRs for each CSC that a bidder may purchase in the auction that will ensure the bidder will not exceed the lower of the TCR limitation described in Section 7.5.9, Limitation on Ownership or Control of TCRs, or a bidder's self-imposed TCR limit set by the bidder prior to the auction.

(c) The bidder's credit limit approved by ERCOT or, if provided, the bidder's self-imposed maximum credit Obligation will be enforced as a constraint such that the summation over all bids of the product of the awarded TCRs and the bidder's bid price is less than or equal to the lower of the bidder's self-imposed maximum Obligation or the credit limit approved by ERCOT. The bidder's self-imposed maximum credit Obligation cannot exceed the credit limit approved by ERCOT.

(d) Bids may be submitted for TCRs for any individual CSC and for weighted combinations of CSCs. Each bid must be non-negative and shall contain the maximum quantity of TCRs, the maximum price, and the distribution weights of the TCRs among the CSCs. The distribution weight shall be submitted with non-negative ratios (with up to three decimal places) that sum to one (1.000), as illustrated in the table below.

Examples of Allowable Bids

Bidders and Bids	CSC 1 Weighting	CSC 2 Weighting	CSC 3 Weighting	Bid Price ($ per MWh)	Maximum Quantity (TCRs)
A1	0.2	0.3	0.5	$10.00	300
A2	1.0	0.0	0.0	$5.00	185
B	0.2	0.5	0.3	$11.25	250
C1	0.6	0.3	0.1	$7.50	240
C2	1.0	0.0	0.0	$1.00	100
D1	0.0	0.5	0.5	$9.50	320
D2	0.0	1.0	0.0	$3.00	140
D3	0.0	0.0	1.0	$2.50	170

NOTE: 3 decimal places for weightings and bid price allowable.

(2) The auction system will award a combination of TCRs that maximizes the sum of bid prices times the awarded MW for the respective bids while simultaneously observing all

applicable constraints. ERCOT shall award TCRs in quantities rounded to three decimal places.

(3) The TCR clearing price for a CSC will be equal to the corresponding Shadow Price of the marginal TCR awarded on that CSC. The Shadow Price is representative of the decremental bid-based revenue that would be produced from the TCR auction if one less TCR were available to be auctioned on that CSC.

(4) If all of the annual TCRs available for a CSC in the annual auction are not awarded (excluding fractional rounding), the TCR clearing price for that CSC shall be determined to be zero (0.0) dollars per MWh. The TCRs not awarded/purchased in the annual auction will be included in the monthly auction.

(5) If all of the TCRs available for a CSC in the monthly auction are not awarded (excluding fractional rounding), the TCR Clearing Price for that CSC shall be determined to be zero (0.0) dollars per MWh. The TCRs not awarded/purchased in the monthly auction will not be sold. Payments for TCR and PCR Invoices shall be due five (5) Bank Business Days after issuance of the Invoice. Any unpaid TCRs and PCRs that remain outstanding after their Invoice date shall be forfeited by the awardees and, with respect to TCRs and PCRs from the annual auction, included in the following monthly auctions.

(6) The linear programming solution will solve for one optimal solution, which may result in some bids at the clearing price not being awarded a TCR. This situation may be minimized because bid prices and bid ratios can be submitted with up to three decimal places.

(7) The auctioneer shall announce the results of the auction simultaneously to all TCR bidders, by posting the results on the MIS. For each CSC, the total quantity of TCRs awarded, the TCR clearing price, and list of all bids will be posted. The identity of the bidders will not be posted.

(8) When an Entity is awarded TCRs as a result of an auction, the TCRs will not become the property of the awardees and the TCRs will not be placed in their accounts until the TCR Invoices have been paid in full. TCRs awarded are considered when determining ownership. Ownership of TCRs in a secondary transfer does not change until the recipient accepts the transfer. Until such time, the initiator of the secondary transfer is considered the owner of the TCRs.

(9) The twenty-five percent (25%) limit shall be applied to secondary transfers. When a recipient accepts a secondary transfer, the number of TCRs the recipient owns in any hour for a given CSC during the month will be added to the amount of the TCRs they will receive as a result of the secondary transfer. If the total exceeds a bidder’s twenty-five percent (25%) limit for the CSC, the secondary transfer shall be cancelled. Electronic Notice shall be given to the secondary transfer initiator and recipient of the cancellation.

7.5.4 Allocation Method and Timing for Distributing TCR Auction Revenues

The TCR auction revenues from each annual auction and PCR revenues will be divided into monthly revenues in the same proportion as ERCOT's monthly energy forecast. This amount will be added to the monthly auction revenue. The total monthly revenues from the auctions will be credited to QSEs once per month on a monthly Load Ratio Share for the ERCOT peak operating interval during the month basis. These revenues will be paid to QSEs no later than the 15th of the following month. PCR holders will be issued invoices that are based on 15 percent of the TCR clearing price from the annual auction. Payment of these invoices is required prior to the distribution of PCRs.

Any difference between the directly assigned Congestion costs charged by ERCOT and Zonal Congestion credits paid to TCR holders for any 15-minute interval will be credited or charged to all QSEs on a Load Ratio Share basis for the same 15-minute interval. ERCOT shall provide a report to be published on its MIS which details by interval, any Zonal Congestion revenue shortfalls or surpluses. The report shall be published on a monthly basis within seven (7) Business Days of the end of a month for the prior month's activity. The report shall provide a description of the methodology and billing determinants used to determine and assess any revenue shortfalls or surpluses, and shall include any billing determinants necessary to replicate the results in the report, to the extent such billing determinants are not already available.

7.5.5 TCR Settlement

To participate in ERCOT's TCR settlements, a TCR holder need not be a QSE nor be represented by a QSE, but must be registered as a TCR Account Holder with ERCOT and have the ability to make and accept electronic transfer of funds.

$$TCRUL_{nq} = -1 * \left(MAUCR_n + AAUCR * \frac{MEnergy_n}{\sum_{All\ Months} MEnergy_n} \right) * LSR_{nq}$$

Where:

n	Month
q	QSE
$TCRUL_{nq}$	TCR Auction Revenue Uplift per QSE per month
$MAUCR_n$	Monthly TCR Auction Revenue
$AAUCR_n$	Annual TCR Auction Revenue plus PCR revenues
$Menergy_n$	Monthly Energy Forecast
LSR_{nq}	QSE's Load Share Ratio in that month's peak interval

Congestion credits, calculated as described below, will be determined based on the record of ownership in ERCOT's database, at the end of the day for which the TCRs are effective, for the relevant CSC, based on the published Shadow Price(s) for the same. The TCR holders will be paid Congestion credits based on their TCR ownership the day after direct assigned Invoice payments are due in accordance with the Settlement Calendar in Section 9, Settlement and Billing.

$$\mathbf{TCRPAY_{hp} \quad = \quad -1 * \Sigma\, (TCR_{CSChp} + PCR_{CSChp}) * (\Sigma\, (SP_{CSCi}/4)_i + SPC_{CSCh}))_{CSC}}$$

Where:

h	Hour being calculated
i	Intervals within the hour
p	TCR owner of record
CSC	Commercially Significant Constraint
CSC_{RPiq}	CSC Replacement Reserve related Congestion charge, per interval, per QSE
TCR_{CSChp}	Total number of TCRs owned per hour, per TCR owner of record
PCR_{CSChp}	Total number of PCRs owned per hour, per PCR owner of record
SP_{CSCi}	BES Shadow Price per CSC, per interval
SPC_{CSCh}	RPRS Capacity Shadow Price per CSC, per hour
$TCRPAY_{hp}$	TCR payment per hour, per TCR owner of record

7.5.6 Direct Allocation of Pre-assigned Congestion Rights

Upon the zonal method being implemented and once auctioned TCRs are available for use, Municipally Owned Utilities (MOUs) and Electric Cooperatives (ECs) which own or have a long-term (greater than five (5) years) contractual commitment for annual capacity and energy from a specific remote Generation Resource, and that commitment was entered into prior to September 1, 1999, are eligible for PCRs. In addition, MOUs and ECs which have a long-term (greater than five (5) years) allocation from the federal government for annual capacity and energy produced at a federally-owned hydroelectric Generation Resource, and that allocation was in place prior to September 1, 1999, are eligible for PCRs. The PCRs will be allocated as follows:

(1) PCRs are available on an annual basis until the date upon which a MOU or EC implements retail Customer Choice, or, alternatively, until such other date as may be specified by Order of the Public Utility Commission of Texas (PUCT). Non Opt-In Entities (NOIEs) that opt in after the first of the year shall pay a pro rata share of the full value for remaining months: (Applicable Annual TCR Clearing Price * 85% * Quantity of PCRs * Number of hours remaining in the year).

(2) The cost of PCRs shall be equal to fifteen percent (15%) of the applicable annual TCR auction clearing price for each CSC for which a PCR is allocated.

$$\mathbf{PCRINV_{yp} \quad = \quad \Sigma\, ((ATCRCP_{CSCyp} * .15) * PCR_{CSCyp} * H))_{CSC}}$$

Where:

p	PCR owner of record

y	Year
ATCRCP	Annual TCR Clearing Price ($/MW)
CSC	Commercially Significant Constraint
H	Number of Hours eligible for PCRs (hours/year)
PCR_{CSCyp}	Total number of PCRs allocated for each of the CSCs, per PCR owner of record, for a given year (MW)
$PCRINV_{yp}$	TCR payment per hour, per TCR owner of record ($/year)

(3) The allocation of PCRs to any single Entity shall not exceed twenty-five percent (25%) of the total available TCRs at a CSC interface for any single direction.

(4) The distribution of PCRs will be sufficient to isolate the MOUs and ECs from any direct-assigned costs associated with transporting the output of their remote Generation Resources to their native Load.

(5) ERCOT shall distribute PCRs and accordingly populate the TCR ownership database for those months where the NOIE meets eligibility requirements. PCRs will be included in applicable monthly TCR auctions when the NOIE does not meet eligibility requirements across the year.

(6) PCRs may be traded in the secondary market.

(7) Holders of PCRs shall not be precluded from participating in the market to purchase additional TCRs.

7.5.7 Secondary Market Exchange of Transmission Congestion Rights

Market Participants can exchange TCRs and PCRs in any secondary market. ERCOT will initially populate a database of hourly TCR holders with the annual and monthly first-purchasers of TCRs and hourly PCR holders. Subsequent holders or owners (other than first-purchasers) of the TCRs and PCRs who want the change in ownership to be recorded in the ERCOT TCR ownership database will be responsible for assuring that the sellers report the transactions to ERCOT's satisfaction and that the sellers authorize the transaction within the ERCOT database in accordance to ERCOT's procedures. A TCR and PCR may change ownership in the ERCOT TCR ownership database through the end of the Adjustment Period of the Operating Hour for which it is designated to hedge Congestion costs.

7.5.8 Transmission Congestion Right Value Under Physical Curtailment or De-rating

TCRs and PCRs will retain their full value even in the event of physical curtailment or flow limitation below the megawatt quantity for which TCRs were defined on any given CSC path.

7.5.9 Limitation on Ownership or Control of TCRs

(1) No Entity combined with its Affiliates may, either directly or indirectly, own, control, or receive the revenue from more than twenty-five percent (25%) of the total available TCRs and/or PCRs at a CSC interface for any single direction for a given hour. The total available TCRs for the annual auction and each monthly auction are determined pursuant to Section 7.5.3.1, Annual and Monthly Auction Summary, and included in the Auction Notice posted pursuant to Section 7.5.3.2.1, TCR Auction Notices.

(2) For purposes of this Section, the total number of TCRs available at a CSC interface for any single direction for a given hour is the greater of (a) the total quantity of TCRs available for annual distribution for that CSC interface, direction, and hour, as determined under Section 7.5.2.1, Annual TCR Quantities, or (b) the total quantity of TCRs for the monthly distribution for that CSC interface, direction, and hour, as determined under Section 7.5.2.2, Monthly TCR Quantities.

(3) If an Entity engages in a transaction with a counter-party, whereby the total ownership or control of the combined Entities exceeds the twenty-five percent (25%) limitation, then any TCRs owned by the counter-parties are not, solely by virtue of that transaction, included in the TCRs that the Entity combined with its Affiliates owns, or controls.

7.5.10 Transition of Transmission Congestion Rights to Congestion Revenue Rights

ERCOT will refund to TCR/PCR owners the annual TCR/PCR auction revenues and monthly TCR auction revenues for all remaining days of the year that follow the Texas Nodal Market Implementation Date. ERCOT will make refunds to TCR/PCR owners no later than thirty (30) Business Days following the start of the Texas Nodal Market.

The total refund of auction revenues to a TCR/PCR owner of record is calculated as follows:

$$\mathbf{TCRRAMT_p = -1 * (TCRMR_p + TCRAR_p + TCRRR_p)}$$

ERCOT shall refund each TCR owner of record its awarded monthly TCRs that are no longer effective for the month of Texas Nodal Market Implementation, including any monthly TCRs already awarded for a subsequent month, calculated as follows:

$$\mathbf{TCRMR_p = (MAUCR_{m,\,p} * MRP) + MAUCR_{n>m,\,p}}$$

ERCOT shall refund each TCR/PCR owner of record its awarded annual TCRs/PCRs that are no longer effective for the month of Texas Nodal Market Implementation, calculated as follows:

$$\mathbf{TCRAR_p = AAUCR_p * (MEnergy_m / (} \sum_{All\ Months} MEnergy_n \mathbf{) * MRP}$$

ERCOT shall refund each TCR owner of record any remaining annual TCRs/PCRs for all months following the month of the Texas Nodal Market Implementation, calculated as follows:

$$\mathbf{TCRRR_p = AAUCR_p * (\sum_{n>m} MEnergy_n / (} \sum_{All\ Months} MEnergy_n \mathbf{))}$$

Where:

TCRRAMT	TCR/PCR Refund Amount per TCR/PCR owner of record
TCRMR	TCR Monthly Refund amount per TCR owner of record for the month of Texas Nodal Market Implementation
TCRAR	TCR/PCR Annual Refund amount per TCR/PCR owner of record for the month of Texas Nodal Market Implementation
TCRRR	TCR/PCR Annual Remaining Refund amount per TCR/PCR owner of record for the months following Texas Nodal Market Implementation
MRP	Monthly Refund Percentage calculated as the number of days remaining in the Texas Nodal Market Implementation month divided by the total number of days in the Texas Nodal Market Implementation month
MEnergy	Monthly Energy Forecast
MAUCR	Monthly TCR Auction Revenue
AAUCR	Annual TCR/PCR Auction Revenue
n	Month
m	Month of Texas Nodal Market Implementation
p	TCR/PCR owner of record

7.6 Incorporation of Reliability Must-Run and Out of Merit Order Resources

RMR and OOM Resources will be used for Congestion Management as described in Sections 4, Scheduling, Section 5, Dispatch and Section 6, Ancillary Services. RMR and OOM Resources will be used for Congestion Management only in the absence of bid-based solutions to alleviate Local Congestion. RMR and OOM Resources will be compensated in accordance with Section 6.8, Compensation for Services Provided.

7.7 Remedies to Congestion Through Transmission Expansion

ERCOT will review the cost of correcting localized transmission limitations through new construction or other means, and will compare this to the costs incurred to correct those problems. ERCOT shall publish the average cost of the constraint by period for each transmission limitation subtotaled by TDSP. This information will be included in ERCOT's Annual Transmission Planning Report. If the projected or actual cost of ERCOT directed Congestion Management including all energy and capacity tools, is greater than the cost of correcting the transmission limitations through construction of Facilities, then ERCOT may recommend an upgrade of Facilities to the TDSP.

7.8 [RESERVED]

7.9 Trading Hubs

The purpose of this section is to define each Trading Hub, list the transmission buses that are included in each Trading Hub, describe how to calculate the Trading Hub Price for each Trading Hub, and establish the duties of ERCOT and Market Participants related to transactions involving Trading Hubs.

7.9.1 Definition of a Trading Hub

(1) A Trading Hub is a specified group of Transmission Buses (60 kV and above) within the ERCOT System used for scheduling bilateral energy or capacity transactions between one or more Market Participants and/or ERCOT.

(2) All Trading Hubs are defined in Section 7.9.2, ERCOT Trading Hubs, and the only way to create other Trading Hubs is by amending Section 7.9.2 through the Protocol Revision Request process, as described in Section 21, Process for Protocol Revision.

(3) If a Transmission Bus that is included in a Trading Hub is physically removed from service, ERCOT shall file a Protocol Revision Request to revise the appropriate Trading Hub to reflect that event.

(4) Transactions involving a Trading Hub shall be expressed in a minimum of one (1) MW increments, unless specified otherwise in Section 7.9.3.4, Scheduling of Transactions Using ERCOT Trading Hubs.

7.9.2 ERCOT Trading Hubs

7.9.2.1 North 345 kV Trading Hub

(1) The North 345 kV Trading Hub is composed of the following Transmission Buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	ANASW	345	2373	ANNA SS	345	NORTH
2	CN345	345	2372	COLLINSS	345	NORTH
3	WLSH	345	5925	DCEAST	345	NORTH
4	FMRVL	345	1685	FARM SW	345	NORTH
5	LPCCS	345	1684	LAMARPWR	345	NORTH
6	MNSES	345	1695	MOSES	345	NORTH
7	PRSSW	345	1692	PARIS SS	345	NORTH
8	SSPSW	345	1697	SULSP SS	345	NORTH
9	VLSES	345	1690	VALLEY	345	NORTH
10	ALNSW	345	2513	ALLEN1SS	345	NORTH
11	ALNSW	345	2514	ALLEN2SS	345	NORTH
12	ALLNC	345	1855	ALLIANCE	345	NORTH
13	BNDVS	345	970	BEN DV B	345	NORTH
14	BNBSW	345	1869	BENB A T	345	NORTH
15	BBSES	345	3380	BIGBRN	345	NORTH
16	BOSQUESW	345	246	BOSQUESW	345	NORTH
17	CDHSW	345	2420	C HILL	345	NORTH
18	CNTRY	345	1929	CENTURY1	345	NORTH
19	CNTRY	345	1930	CENTURY3	345	NORTH
20	CRLNW	345	2361	CLT NW	345	NORTH
21	CMNSW	345	1440	CMCHE SS	345	NORTH
22	CNRSW	345	2453	CNVIL	345	NORTH
23	CRTLD	345	1931	COURTLND	345	NORTH
24	DCSES	345	1888	DEC T	345	NORTH
25	EMSES	345	1859	EAGLE MT	345	NORTH
26	ELKTN	345	3105	ELKTON	345	NORTH
27	ELMOT	345	3406	ELM MOTT	345	NORTH
28	EVRSW	345	1882	EV WEST	345	NORTH
29	KWASS	345	11690	FANNIN	345	NORTH
30	FGRSW	345	3130	FOR GROV	345	NORTH
31	FORSW	345	2437	FORNEY	345	NORTH
32	FRNYPP	345	12410	FPLEFRB1	345	NORTH
33	FRNYPP	345	12420	FPLEFRB2	345	NORTH
34	GIBCRK	345	967	GIBCRK B	345	NORTH
35	HKBRY	345	2387	HACKBRY	345	NORTH
36	VLYRN	345	2389	IV VR	345	NORTH
37	JEWET	345	3391	JEWETT N	345	NORTH
38	JEWET	345	3390	JEWETT S	345	NORTH

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
39	KNEDL	345	1932	KENNDLE1	345	NORTH
40	KLNSW	345	3422	KILL SS	345	NORTH
41	LCSES	345	3409	LAKE CRK	345	NORTH
42	LIGSW	345	1916	LIG2 T	345	NORTH
43	LEG	345	46020	LIMEST 5	345	NORTH
44	LFKSW	345	3117	LUFKN SS	345	NORTH
45	LWSSW	345	646	LWSSWB	345	NORTH
46	MLSES	345	3100	MARTINLK	345	NORTH
47	MCCREE	345	833	MCCREE B	345	NORTH
48	MDANP	345	1939	MELP S	345	NORTH
49	MDANP	345	1936	MELP56NO	345	NORTH
50	ENTPR	345	3116	MT ENTRP	345	NORTH
51	NCDSE	345	3119	NACOG SE	345	NORTH
52	NORSW	345	2406	NORWD	345	NORTH
53	NUCOR	345	3396	NUCOR	345	NORTH
54	PKRSW	345	1436	PARKER	345	NORTH
55	KMCHI	345	11697	PITTSBRG	345	NORTH
56	PTENN	345	2522	PL TEN	345	NORTH
57	RENSW	345	2355	RENERTPL	345	NORTH
58	RCHBR	345	3133	RICHLND1	345	NORTH
59	RCHBR	345	3134	RICHLND2	345	NORTH
60	RNKSW	345	1853	ROANOKE	345	NORTH
61	RKCRK	345	1880	ROCKY CK	345	NORTH
62	RYSSW	345	2461	ROYSE S	345	NORTH
63	SGVSW	345	2433	SGVL SS	345	NORTH
64	SHBSW	345	3103	SHAMBRGR	345	NORTH
65	SHRSW	345	1918	SHERRY	345	NORTH
66	SHRTP	345	1917	SHERRY T	345	NORTH
67	SCSES	345	3109	STRYKER	345	NORTH
68	SYCRK	345	1935	SYCMR CK	345	NORTH
69	THSES	345	3405	T HOUSE	345	NORTH
70	TMPSW	345	3413	TEMPSSLT	345	NORTH
71	TNP_ONE	345	39950	TNP ONE	345	NORTH
72	TRCNR	345	2432	TRICORN	345	NORTH
73	TRSES	345	3123	TRINDAD1	345	NORTH
74	TRSES	345	3124	TRINDAD2	345	NORTH
75	TOKSW	345	3400	TWIN OAK	345	NORTH
76	VENSW	345	1907	VENUS N	345	NORTH
77	VENSW	345	1906	VENUS S	345	NORTH

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
78	WLVEE	345	2398	W LEVEE	345	NORTH
79	W_DENT	345	988	W.DENT B	345	NORTH
80	WTRML	345	2427	WATMILLW	345	NORTH
81	WCSWS	345	1434	WCPC	345	NORTH
82	WEBB	345	1911	WEBB 1	345	NORTH
83	WHTNY	345	240	WHITNEY	345	NORTH
84	WCPP	345	1421	WILLOWCK	345	NORTH

(2) The North 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.2 South 345 kV Trading Hub

(1) The South 345 kV Trading Hub is composed of the following Transmission Buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	AUSTRO	345	7040	AUSTRO34	345	SOUTH
2	BLESSING	345	8123	BLESSNG6	345	SOUTH
3	CAGNON	345	5056	CAGNON	345	SOUTH
4	COLETO	345	8164	COLETO 6	345	SOUTH
5	CLEASP	345	7050	CRLSPG34	345	SOUTH
6	NEDIN	345	8383	EDNBRG 6	345	SOUTH
7	FAYETT	345	7057	FAYETT34	345	SOUTH
8	FPPYD1	345	7056	FPPYD134	345	SOUTH
9	FPPYD2	345	7055	FPPYD234	345	SOUTH
10	GARFIE	345	7048	GARFIE34	345	SOUTH
11	GUADG	345	7047	GPP	345	SOUTH
12	HAYSEN	345	7043	HAYSN 34	345	SOUTH
13	HILLCTRY	345	5211	HILL CTY	345	SOUTH
14	HOLMAN	345	9073	HOLMAN	345	SOUTH
15	KENDAL	345	7046	KENDAL34	345	SOUTH
16	LA_PALMA	345	8317	LAPALM 6	345	SOUTH
17	LON_HILL	345	8455	LNHILL 6	345	SOUTH
18	LOSTPI	345	7041	LOSTPN34	345	SOUTH
19	LYTTON_S	345	9074	LYTTON	345	SOUTH
20	MARION	345	7044	MARION34	345	SOUTH
21	PAWNEE	345	5725	PAWNESW6	345	SOUTH

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
22	RIOHONDO	345	8318	RIOHND 6	345	SOUTH

23	RIONOG	345	7051	RIONO 34	345	SOUTH
24	SALEM	345	7058	SALEM 34	345	SOUTH
25	SDSES	345	3429	SANDOW	345	SOUTH
26	SANMIGL	345	52	SANMIGEL	345	SOUTH
27	SKYLINE	345	5371	SKYLINE	345	SOUTH
28	STP	345	5915	SO TEX 5	345	SOUTH
29	CALAVERS	345	5400	SPRUCE	345	SOUTH
30	BRAUNIG	345	5475	VON ROSE	345	SOUTH
31	WHITEPT	345	8956	WHITEPT	345	SOUTH
32	ZORN	345	7042	ZORN 34	345	SOUTH
33	ZORN	345	7045	ZORN 34	345	SOUTH

(2) The South 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.3 Houston 345 kV Trading Hub

(1) The Houston 345 kV Trading Hub is composed of the following listed transmission buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	ADK	345	45600	ADICKS 5	345	HOUSTON
2	_BI	345	47000	BELAIR 5	345	HOUSTON
3	CBY	345	40000	CEDARP 5	345	HOUSTON
4	CTR	345	40240	CENTER	345	HOUSTON
5	CHB	345	40255	CHAMBR 5	345	HOUSTON
6	DPW	345	40450	DEPWTR 5	345	HOUSTON
7	DOW	345	42500	DOW345 5	345	HOUSTON
8	RNS	345	40600	FRONTR	345	HOUSTON
9	GBY	345	40700	GRNBYU 5	345	HOUSTON
10	_JN	345	47300	JENETA 5	345	HOUSTON
11	_KG	345	40900	KING 5	345	HOUSTON
12	KDL	345	45972	KUYDAL 5	345	HOUSTON
13	_NB	345	46100	N_BELT 5	345	HOUSTON
14	_OB	345	44500	OBRIEN 5	345	HOUSTON
15	PHR	345	42000	P_H_R_ 5	345	HOUSTON
16	SDN	345	41430	SHELDN 5	345	HOUSTON
17	SMITHERS	345	44650	SMTHRS 5	345	HOUSTON
18	THW	345	45500	T_H_W_ 5	345	HOUSTON
19	WAP	345	44000	W_A_P_ 5	345	HOUSTON
20	_WO	345	46600	WHITOK 5	345	HOUSTON

(2) The Houston 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.4 West 345 kV Trading Hub

(1) The West 345 kV Trading Hub is composed of the following listed transmission buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	ABMB	345	6230	ABMULCE7	345	WEST
2	BOMSW	345	1422	BOWMAN	345	WEST
3	OECCS	345	1020	EHV TIET	345	WEST
4	BTRCK	345	1050	ENRONIPP	345	WEST
5	FSHSW	345	1425	FISHRDSS	345	WEST
6	FLCNS	345	1025	FS COGEN	345	WEST
7	GRSES	345	1430	GRAHAM	345	WEST
8	JCKSW	345	1429	JXBRO SS	345	WEST
9	MDLNE	345	1021	MIDL E T	345	WEST
10	MOSSW	345	1018	MOSS	345	WEST
11	MGSES	345	1030	MRGN CRK	345	WEST
12	DCTM	345	6096	NORTHDC7	345	WEST
13	ODEHV	345	1026	ODES EHV	345	WEST
14	OKLA	345	6100	OKLAEHV7	345	WEST
15	SARC	345	6444	SAREDCK7	345	WEST
16	SWCOG	345	1420	SWEETWTR	345	WEST
17	TWINBUTE	345	6009	TWBT7	345	WEST

(2) The West 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.5 ERCOT Hub Average 345 kV Trading Hub

The ERCOT Hub Average 345 kV Trading Hub Price is the simple average of the North 345 kV Trading Hub Price, South 345 kV Trading Hub Price, Houston 345 kV Trading Hub Price, and West 345 kV Trading Hub Price.

7.9.2.6 ERCOT Bus Average 345 kV Trading Hub

(1) The ERCOT Bus Average 345 kV Trading Hub is composed of the buses listed in Section 7.9.2.1, North 345 kV Trading Hub, Section 7.9.2.2, South 345 kV Trading Hub, Section 7.9.2.3, Houston 345 kV Trading Hub and Section 7.9.2.4, West 345 kV Trading Hub.

(2) Until superseded by implementation of a different market design for the ERCOT market (e.g., a nodal market design), the ERCOT Bus Average 345 kV Trading Hub Price for each interval shall approximately consist of a fifty-six percent (56%) weighting applied to the North 345 kV Trading Hub price, a twenty-two percent (22%) weighting applied to the South 345 kV Trading Hub price, a thirteen percent (13%) weighting applied to the

Houston 345 kV Trading Hub price, and a nine percent (9)% weighting applied to the West 345 kV Trading Hub price. For the exact weights, please refer to Section 7.9.3.4, Scheduling of Transactions Using ERCOT Trading Hubs.

7.9.3 ERCOT Responsibilities

7.9.3.1 Posting of a List of Buses included in Trading Hubs

(1) ERCOT shall post a list of all the buses included in each ERCOT Trading Hub on the public MIS. The list must include the bus name and kV rating as used by ERCOT Operations, the bus number, bus name and kV rating as used in the Steady State Working Group (SSWG) base cases, and the Congestion Zone that the bus is assigned to.

(2) ERCOT shall update the list of buses included in each ERCOT Trading Hub as soon as possible whenever a new Trading Hub is created under this Section 7.9 or when affected Transmission Buses are renamed in either the ERCOT Operations model or the SSWG model.

7.9.3.2 Calculation of Trading Hub Prices

ERCOT shall calculate Trading Hub Prices for each Settlement Interval. The bus price for each Transmission Bus for each Settlement Interval is the Market Clearing Price at that bus as determined elsewhere in these Protocols for that Settlement Interval.

7.9.3.3 Posting of Trading Hub Prices

ERCOT shall post the Trading Hub Prices for each ERCOT Trading Hub for each Settlement Interval as soon as practicable on the public MIS.

7.9.3.4 Scheduling of Transactions Using ERCOT Trading Hubs

(1) Until ERCOT's scheduling system is updated to automatically convert transactions involving Trading Hubs into transactions involving Congestion Zones, Qualified Scheduling Entities (QSEs) having any transaction involving an ERCOT Trading Hub shall convert each such transaction to one that can be expressed as a scheduled transaction between existing Congestion Zones.

(2) Market Participants shall use the following matrix to convert transactions at Trading Hubs to existing Congestion Zones:

	2009 Congestion Zone			
Trading Hub	North	South	Houston	West
North	.976	0.024		
South		0.97	0.03	
Houston	0.050		0.950	
West	0.235			0.765
Bus Average	0.571	0.221	0.123	0.085
ERCOT Average	0.315	0.249	0.245	0.191

ERCOT Protocols
Section 8: Planned Outages and Maintenance Outages of Transmission and Resource Facilities

March 1, 2009

8 PLANNED OUTAGES AND MAINTENANCE OUTAGES OF TRANSMISSION AND RESOURCE FACILITIES

Facility owners shall remain 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.

Prior to taking an RMR or a Synchronous Condenser Unit or Black Start Resource ("Reliability Resources") out of service for a Planned Outage or Maintenance Outage, the Single Point of Contact, as defined in Section 8.2.1, Single Point of Contact, for such RMR Unit, Synchronous Condenser Unit, or Black Start Resource shall 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 as provided in this Section and in accordance with the applicable Agreements.

8.1 Outage Coordination

8.1.1 Role of ERCOT

ERCOT will coordinate and use reasonable efforts, consistent with Good Utility Practice, to accept or approve all Outage schedules for maintenance, repair, and construction of both Transmission and Resources Facilities within the ERCOT System. Under certain circumstances, as set forth in Section 8.3.1, Section 8.5, and Section 8.6.1, ERCOT may reject an Outage schedule.

ERCOT's responsibilities with respect to Outage coordination include:

(1) Approval of schedules 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;

(2) Assessment of the adequacy of available Resources relative to forecasts of Load and reserve requirements;

(3) Coordination and approval of schedules for Planned Outages of Reliability Must Run (RMR) Units subject to the terms of the applicable RMR Agreements;

(4) Coordination and acceptance or rejection of schedules for Planned Outages of Resource Facilities scheduled to occur within eight (8) days of request;

(5) Coordination with, and approval of, Outages associated with Black Start Units in accordance with the Black Start Unit Agreement;

(6) Review and coordination of changes to existing twelve (12) month Resource Outage plans to determine how changes will affect ERCOT System Reliability. Such changes include Resource Outages not previously included in the plan;

(7) Monitoring of the performance of Resources and TSPs with respect to Outage schedule updates;

(8) Posting of all proposed and approved schedules for Planned Outages and Maintenance Outages of Transmission Facilities on the ERCOT MIS;

(9) Creation of aggregated schedules of Planned Outages for Resources and the posting of such schedules on the ERCOT MIS;

(10) Monitoring of Transmission Facility and Resource Facility Forced Outages and Maintenance Outages of immediate nature and implementing responses to such Outages as provided in these Protocols;

(11) Establishment and implementation of communication procedures for TSPs to request approval of Transmission Facility Planned Outage and Maintenance Outages schedules; and for Resources' designated Single Points of Contact to submit Outage programs and to coordinating Resource Outages;

(12) Establishment and implementation of record keeping procedures for the retention of all requested Planned Outages, Maintenance Outages, and Forced Outages; and

(13) Planning and analysis of Transmission Facility Outages.

8.1.2 Planned Outage or Maintenance Outage Data Reporting

Resource Entities shall use reasonable efforts, consistent with Good Utility Practice, to continually update their Outage schedule plans. All information submitted in relation to Planned Outages or Maintenance Outages must be submitted by the Resource or the Transmission Service Provider (TSP) in accordance with this section. Resources and TSPs shall supply to ERCOT the data defined in these Protocols and the Operating Guides.

8.1.3 Rolling Twelve Month Outage Planning and Update

8.1.3.1 Transmission Facilities

TSPs must provide ERCOT a written Planned Outage or Maintenance Outage program in an ERCOT provided format for the next twelve (12) months updated monthly for a rolling twelve (12) month period. Planned Outage or Maintenance Outage scheduling data for Transmission Facilities shall be kept current. Updates must identify all changes to any previously proposed Planned Outages or Maintenance Outage and any additional Planned Outages or Maintenance Outage anticipated over the next twelve (12) months. ERCOT will coordinate in-depth reviews of the twelve (12) month programs with the TSPs at least two (2) times a year.

8.1.3.2 Resources

Resource Entities must provide ERCOT a written Planned Outage and Maintenance Outage program for the next twelve (12) months, in an ERCOT provided format updated for a rolling twelve (12) month period. Planned Outage and Maintenance Outage scheduling data for Resource Facilities shall be kept current. Updates shall identify any changes to previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outage anticipated over the next twelve (12) months.

8.2 Communications Regarding Resource Facility and Transmission Facility Outages

8.2.1 Single Point of Contact

All communications concerning Planned Outage or Maintenance Outage shall be between ERCOT and the designated "Single Point of Contact" for each TSP or Resource Entity. The TSP or Resource Entity shall identify, in its initial request or response, the Single Point of Contact, along with primary and alternate means of communication. The Resource Entity or Transmission Entity shall submit a Notice of Change of Information (NCI) form when changes occur in a Single Point of Contact. This identification will be confirmed in all communications with ERCOT regarding Planned Outage or Maintenance Outage requests.

The Single Point of Contact must be either a person or a position available seven (7) days per week and twenty-four (24) hours per day for each Resource Entity and TSP. The Resource Entity shall designate its QSE as its Single Point of Contact. The Single Point of Contact for the TSP shall be designated in accordance with the ERCOT Operating Guides.

8.2.2 Method of Communication

Communication between ERCOT and TSPs or Resource Entities shall be accomplished according to ERCOT procedures in compliance with these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages shall be processed through the ERCOT Outage Scheduler on the ERCOT MIS, except for Forced Outages and Maintenance Outages, which shall be communicated to ERCOT immediately by voice communication and subsequently entered into the Outage Scheduler.

8.2.3 Reporting for Planned Outages and Maintenance Outages of Resource and Transmission Facilities

Resource Entities and TSPs shall submit information regarding proposed Planned Outages and Maintenance Outages of Facilities in accordance with procedures adopted by ERCOT. The Obligation to submit such information applies to Resource Entities and TSPs that have operation and maintenance responsibility for Transmission Facilities and Resources constituting or impacting the ERCOT System. Resource Entities and TSPs are not obligated to submit information for Transmission Facilities or Resources that are not part of the ERCOT System unless such information is required for regional security coordination as determined by ERCOT.

8.2.4 Management of Transmission Forced Outages or Maintenance Outages

In the event of a Forced Outage, the Resource Entity or TSP may remove the affected equipment from service immediately and must immediately notify ERCOT of its action. Forced Outages may require ERCOT to review and/or withdraw approval of previously approved or accepted, as applicable Planned Outage or Maintenance Outage schedules to ensure reliability.

For Maintenance Outages, the Resource Entity or TSP shall notify ERCOT of any Resource or Transmission Facility Maintenance Outage according to the Maintenance Outage Levels defined in Section 2, Definitions and Acronyms. ERCOT will coordinate the removal of Facilities from service within the defined timeframes as specified by the TSP or Resource Entity in its Notification to ERCOT.

ERCOT may require supporting information describing Forced Outages and Maintenance Outages. ERCOT may reconsider and withdraw approvals of other previously approved Transmission or Reliability Resource Outages as a result of Forced Outages or Maintenance Outages, if necessary, in ERCOT's determination to protect system reliability. When ERCOT accepts a Maintenance Outage, ERCOT shall coordinate timing of the appropriate course of action as specified in Section 8.3.8, Information for Inclusion in Transmission Facility Outage Requests, and Section 8.4.1, Resources Outage Plan.

Removal of Resource or Transmission Facilities from service under Maintenance Outages shall 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.

8.2.5 Notification of Forced Outage, Unavoidable Extension of Planned or Maintenance Outage Due to Unforeseen Events

If a Planned or Maintenance Outage is not completed within the ERCOT 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.

8.3 ERCOT Approval of Transmission System Outages

8.3.1 Approval of Planned Outage and Maintenance Outage of Transmission Facilities

Proposed Transmission Facility Planned Outage or Maintenance Outage information submitted by a TSP 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 shall not be deemed to have approved the Outage schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP of its approval pursuant to procedures adopted by ERCOT. ERCOT shall evaluate requests as set forth in Section 8.3.10, Evaluation of Transmission Facility Planned Outage or Maintenance Outage Requests.

ERCOT shall approve Planned Outages and accept Maintenance Outages of Transmission Facilities schedules unless, in ERCOT's determination, the requested Transmission Facility Planned Outages or Maintenance Outages of Transmission Facilities would cause ERCOT to violate applicable reliability standards. ERCOT shall transmit its approvals and rejections to TSPs via the ERCOT Outage coordination interface. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 8.3.6, Withdrawal of Approval and Rescheduling of Approved Planned Outages and Maintenance Outages of Transmission Facilities.

8.3.2 Receipt of TSP Requests by ERCOT

ERCOT shall acknowledge each request for approval of a Transmission Facility Planned Outage schedule within two (2) 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.

8.3.3 Timelines for Response by ERCOT

For Transmission Facility 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 will approve or reject no later than:**
Three (3) days	0000 hours, one (1) day prior to start of the proposed Outage
Between four (4) and eight (8) days	0000 hours, two (2) days prior to start of the proposed Outage
Between nine (9) days and forty-five (45) days	Four (4) days prior to the start of the proposed Outage
Between forty-six (46) days and ninety (90) days	Thirty (30) days prior to the start of the proposed Outage
Greater than ninety (90) days	Seventy-five (75) days prior to the start of the proposed Outage

ERCOT will make reasonable attempts to accommodate unusual circumstances that support TSP requests for approval earlier than required by the schedule above.

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.

When ERCOT rejects a request for an Outage, ERCOT shall provide TSPs, in written or electronic form, suggested amendments to the schedules of Planned Outage or Maintenance Outage of Transmission Facilities. Any such suggested amendments accepted by the TSP shall be processed by ERCOT as a Planned Outage or Maintenance Outage of Transmission Facility request in accordance with this Section.

8.3.4 Delay

ERCOT may delay its approval or rejection of a proposed Planned Outage or Maintenance Outage of a Transmission Facility schedule if the requesting TSP has not submitted sufficient or complete information within the time frames set forth herein.

8.3.5 Rejection Notice

If ERCOT rejects a request, ERCOT shall provide the TSP a written or electronic rejection Notice that shall include:

(1) Specific concerns causing the rejection; and

(2) Possible remedies or transmission schedule revisions, if any, that might mitigate a basis for approval rejection.

ERCOT may reject Planned Outages or Maintenance Outages of Transmission Facilities only:

(1) In order to protect system reliability or security;

(2) Due to insufficient information regarding the Outage; or

(3) Due to failure to comply with approval process requirements, as specified herein.

When multiple proposed Planned Outages or Maintenance Outages cause a reliability or security concern, ERCOT will:

(1) Communicate with each TSP to see if the TSP will adjust its proposed Planned Outage or Maintenance Outage schedule;

(2) Determine if the multiple TSPs will agree to an alternative Outage schedule; or

(3) Reject one or more proposed Outages, considering order of receipt and impact to the ERCOT Transmission Grid, at ERCOT's discretion.

8.3.6 Withdrawal of Approval and Rescheduling of Approved Planned Outages and Maintenance Outages of Transmission Facilities

If ERCOT believes it cannot meet the applicable reliability standards and has exercised reasonable options, ERCOT shall have the authority to withdraw approval for a Planned Outage or Maintenance Outage schedule. 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.

In determining, whether to withdraw approval, ERCOT may give due consideration to whether the Planned Outage or Maintenance Outage affects public infrastructure if ERCOT is made aware of such potential impacts by the TSP (e.g. impacts on highways, ports, municipalities, counties).

8.3.7 Priority of Approved Planned Outages

In considering TSP requests, ERCOT shall give priority to approved Planned Outage and Maintenance Outage schedules previously posted to the ERCOT MIS.

8.3.8 Information for Inclusion in Transmission Facility Outage Requests

Transmission Facility Outage requests submitted by TSPs shall include the following Transmission Facility-specific information:

(1) The identification of the Transmission Facility, including TSP and location;

(2) The nature of the work to be performed during the proposed Transmission Facility Outage;

(3) The preferred start and finish date for each proposed Transmission Facility Planned and Maintenance Outage;

(4) The time required to: (i) terminate the Transmission Facility Planned Outage and Maintenance Outage and (ii) restore the Transmission Facility to normal operation;

(5) Identification of primary and alternate telephone numbers for the TSP's Single Point of Contact, as described in Section 8.2.1, Single Point of Contact, and the name of the individual submitting the information;

(6) The amount of scheduling flexibility (i.e., the earliest start date and the latest finish date for the Outage);

(7) Identification of any Transmission Facility that must be out of service to facilitate the TSP's request;

(8) Identification of any remedial actions or special protection systems necessary during this Outage and the contingency that will require the remedial action or relay action; and

(9) Any other relevant information related to the proposed Outage.

When ERCOT accepts a Maintenance Outage, ERCOT will coordinate the timing of the appropriate course of action. The requesting TSP will notify ERCOT verbally of the Outage and coordinate the time.

8.3.9 Additional Information Requests

ERCOT may request additional information or seek clarification from the TSP regarding the information submitted for a proposed Outage.

8.3.10 Evaluation of Transmission Facility Planned Outage or Maintenance Outage Requests

ERCOT shall evaluate requests for approval of Transmission Facility Planned Outages and Maintenance Outages to determine if any one or a combination of proposed Outages may cause ERCOT to violate applicable reliability standards. ERCOT's evaluations shall take into consideration factors including, but not limited to, the following:

(1) Forecast of peak Demand conditions;

(2) Outage plans submitted by Resource Entities and TSPs pursuant to Section 8.1, Planned Outages and Maintenance Outages of Transmission and Resource Facilities;

(3) Forced Outages of Transmission Facilities;

(4) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software;

(5) Previously approved Planned Outages and Maintenance Outages;

(6) Impacts on the transfer capability of DC Ties; and

(7) Good Utility Practice with respect to Transmission Facility maintenance.

8.3.11 Transmission Report

ERCOT will publish on the MIS, initially and when updated, a summary of approved Transmission Facilities Planned Outages, Accepted Maintenance Outages, and Forced Outages.

8.4 Acceptance of Proposed Planned Outages of Resources other than Reliability Resources

Except as provided below, ERCOT shall accept Outage schedules and changes to Outage schedules submitted by a Resource Entity (other than Reliability Resources) to ERCOT more than eight (8) days prior to the proposed start date of the Outage. A Generation Entity shall not submit an Outage schedule or change to an Outage schedule for a Generation Resource Outage lasting greater than one hundred eighty (180) days in length prior to ERCOT issuing a determination that the Generation Resource is not required to support ERCOT System reliability pursuant to Section 6.5.8.1, Long-term Outage Notifications and Initiation and Approval of RMR Agreements. ERCOT may reject a submission which does not meet these requirements.

If a Resource Plans to initiate a Planned or Maintenance Outage within eight days that has not been previously included in the Resource's written Planned Outage and Maintenance Outage program, the Resource Entity must immediately notify ERCOT and include in its Notification whether the Outage is Forced, Maintenance (Level I, II, or III), or Planned. ERCOT's response to this Notification will be as follows:

(1) Forced and Maintenance Level Outage proposals will be accepted by ERCOT and coordinated within the time frames specified in Section 2.1, Definitions.

(2) Planned Outage proposals will either be accepted or, if after determining that the Outage proposal will impair ERCOT's ability to meet applicable reliability standards and other solutions cannot be exercised, ERCOT may reject the proposal.

If, at any time during the next eight (8) days, a Resource Entity plans to bring back a unit early or otherwise show a unit as available that was previously shown under Planned or Maintenance Outage, the Resource Entity will notify ERCOT immediately regarding this change. ERCOT will accept this change and, in the event that a transmission Outage requires the affected Resource(s) to be Off-line, ERCOT will coordinate between the TDSP and the Resource owner to schedule a time mutually agreeable to both parties for the unit to be Off-line. If mutual Agreement cannot be reached, then ERCOT will decide, considering expected impact on system security, future Outage plans, and participants.

8.4.1 Resources Outage Plan

Resource Entity Outage requests shall include the following information:

(1) The primary and alternate phone number of the Resource Entity's Single Point of Contact for Outage coordination;

(2) The Resource Identified by common name;

(3) The net megawatts of capacity the Resource Entity anticipates will be available during the Outage (if any);

(4) The estimated start and finish date for each Planned and Maintenance Outage;

(5) 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

(6) The nature of work to be performed during the Outage.

When ERCOT accepts a Maintenance Outage, ERCOT will coordinate the timing of the appropriate course of action within the Resource specified timeframe. The QSE will notify ERCOT verbally of the Outage and coordinate the time.

8.4.2 Additional Information Requests

ERCOT may request additional information from a Resource Entity regarding the information submitted as part of a Resource Outage plan. ERCOT shall not unnecessarily delay requests for information in terms of the required response time.

8.4.3 Acceptance of Changes to a Resource Outage Plan within Eight (8) Days of Planned Start

Resource Entities must request acceptance from ERCOT only for new Resource Outages or changes to a previously accepted planned Resource Outage scheduled to occur within eight (8) days of the request.

Planned Outage proposals will either be accepted or, if after determining that the Outage proposal will impair ERCOT's ability to meet applicable reliability standards and other solutions cannot be exercised, ERCOT may reject the proposal.

ERCOT will reject such a request within this eight (8) day reliability window if it expects this Outage to result in a violation of ERCOT reliability criteria.

ERCOT will accept all changes to a Resource Outage plan submitted by a Resource Entity more than eight (8) days before the planned start date for the Outage. ERCOT may discuss with Resource Entities or QSEs any Outage requests which are expected to result in a violation of an ERCOT reliability criteria or which may result in cancellation of a planned transmission Outage in an attempt to reach a mutually agreeable resolution, including rescheduling the Outage in a manner agreeable to the Resource.

Any Resource may return from a Planned Outage when the scheduled work is complete without ERCOT acceptance. In the event of such an early return the Resource or QSE will notify ERCOT of the early return as much in advance as practicable, but no later than at least two (2) hours prior to startup.

8.4.4 Timelines for Response by ERCOT

ERCOT shall accept or reject each request in accordance with the following table:

Amount of time between a Request for acceptance of a Planned Outage and the scheduled start of the proposed Outage:	**ERCOT will accept or reject no later than:**
Between one (1) and two (2) days	Within eight (8) Business Hours of receipt by ERCOT

Between three (3) and eight (8) days	0000 hours, two (2) days prior to start of the proposed Outage
Greater than eight (8) Days	Accepted, but ERCOT may discuss reliability and scheduling impacts to minimize hazard/cost to ERCOT System in an attempt to accomplish minimum overall impact.

8.4.5 Delay

ERCOT may delay its acceptance or rejection of a proposed Planned Outage schedule if the requesting Resource Entity has not submitted sufficient or complete information within the time frames set forth in this Section. Review periods for Outage consideration shall not commence until sufficient and complete information is submitted to ERCOT as described in Section 8.4.1, Resources Outage Plan.

8.4.6 Opportunity Outage

Opportunity Outages are a special category of Planned Outages that may be accepted by ERCOT when a specific Resource has been forced off line due to a Forced Outage and the Resource has been previously accepted for a Planned Outage during the next eight (8) days.

When a Forced Outage occurs on a Resource that has an approved or accepted Outage scheduled within the following eight (8) days, the Resource may remain Off-line and start the accepted/approved Outage earlier than scheduled. The QSE must notify ERCOT with as much Notice as practicable.

8.4.7 Outage Returning Early

A Resource that completes a scheduled Outage early may resume operation without ERCOT acceptance; however, the Resource's QSE shall notify the ERCOT Shift Supervisor verbally of the early return prior to resuming service. In the event of such an early return, the Resource or QSE must notify ERCOT of the early return as much in advance as practicable, but no later than at least two (2) hours prior to beginning startup. Within two hours of receiving such request, ERCOT will accept the request unless, as result of complying with the request, If ERCOT cannot maintain system reliability and/or security with this Resource injection. In such a case, ERCOT will issue a Dispatch Instruction to the Resource to stay Off-line.

Prior to an early return from an Outage, a Resource or QSE may inquire of ERCOT if the Resource is expected to be issued a Dispatch Instruction to provide OOM service to zero upon its early return. Notwithstanding any other provisions of these Protocols, if a Resource/QSE makes this inquiry, is notified by ERCOT that it will OOM the unit Off-line if it returns from the Outage early, and still starts within the previously accepted Outage period, then the QSE host to this Resource will not be paid startup and OOM energy compensation as otherwise would be provided for in these Protocols.

8.4.8 Resource Coming On-line

Prior to start-up and synchronizing On-line, a Resource or QSE for the Resource may inquire of ERCOT whether the Resource is expected to be issued a Dispatch Instruction to provide OOM Service to zero (0) MW upon its coming On-line. Notwithstanding any other provisions of these Protocols, if a Resource/QSE makes this inquiry, is notified by ERCOT that ERCOT will provide OOM Dispatch Instructions for the Resource go to zero (0) MW if the Resource comes On-line, and the Resource/QSE still brings the Resource On-line, then the QSE host to this Resource will not be paid OOM Energy compensation as otherwise would be provided for in these Protocols.

8.5 Approval of RMR Unit, Synchronous Condenser Unit or Black Start Resource Outages

ERCOT shall evaluate requests for approval of RMR Unit, Synchronous Condenser Unit, and Black Start Resource (Reliability Resources) Outages to determine if any one or a combination of proposed Outages may cause ERCOT to violate applicable reliability standards. ERCOT's evaluations shall take into consideration factors including, but not limited to, the following:

(1) Load Forecast;

(2) All other known Outages; and

(3) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software.

8.5.1 Timelines for Response by ERCOT on Reliability Resource Outages

ERCOT shall approve requests for Planned Outages of Reliability Resources unless, in ERCOT's determination, the requested Outage would cause ERCOT to violate applicable reliability standards. 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 will approve or reject no later than:**
No less than thirty (30) days	Fifteen (15) days prior to start of the proposed Outage
Greater than forty-five (45) days	Thirty (30) days prior to the start of the proposed Outage

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. ERCOT will approve or reject Maintenance Outages on Reliability Resources as follows:

Amount of time between a Request for approval of a proposed Outage:	ERCOT will approve or reject no later than:
Between three (3) and eight (8) days	0000 hours, two (2) days prior to start of the proposed Outage
Between nine (9) and thirty (30) days	Four (4) days prior to the start of the proposed Outage

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 will transmit approvals electronically.

8.5.2 Changes to an Approved Reliability Resource Outage Plan

Once ERCOT has approved a Reliability Resource Planned Outage, a Market Participant may submit to ERCOT a change request form (in addition to entering the change in the Outage Scheduler) no later than thirty (30) days before the scheduled start date of the approved Outage. ERCOT will accept or reject the proposed change within fifteen (15) days of receiving the change request form. ERCOT may, at its discretion, relax the thirty (30) day Notice requirement.

8.6 Management of Resource Outages other than Reliability Resources

8.6.1 Rejection of Proposed Resource Outages

This Section 8.6.1, Rejection of Proposed Resource Outages, applies only to Planned Outages that are either changes to existing Outage schedules submitted eight (8) days or less prior to the Outage start date, to new Outage requests submitted eight (8) days or less prior to the proposed start date for the Outage.

If a proposed Resource Outage, in conjunction with previously accepted Outages, would cause a violation of applicable reliability standards, ERCOT will reject the Outage acceptance and notify the relevant Single Point of Contact for the Resource requesting the Outage. Provided, however, ERCOT will consider other reasonable means to avoid the violation of applicable reliability standards prior to issuing such Outage rejection.

When a proposed Resource Planned Outage and/or a Transmission Facility Outage cause reliability or security concerns, ERCOT will:

(1) Communicate with each requesting Market Participant to try to identify how to adjust the proposed Outage requests; and

(2) Reject one or more proposed Transmission or Reliability Resource Outage(s), considering order of receipt and impact to the ERCOT System, at ERCOT's discretion. If security cannot be maintained after these actions, then rejection of Resource Outages in order of receipt or impact will be considered.

ERCOT will normally reject proposed Outages when its analysis indicates an Outage will result in the insecurity or unreliability of the ERCOT System. Based upon security and reliability analysis results, ERCOT shall investigate possible Remedial Action Plans for all insecure states and strive to maximize transmission usage consistent with reliable operation. ERCOT will reject Outage requests if it cannot identify Remedial Action Plans for any security concerns relating to an Outage.

8.6.2 Emergency Coordination

If ERCOT forecasts an inability to meet applicable reliability standards and it has exercised all other reasonable options. ERCOT shall inform the Single Point of Contact for the affected Market Participant, both orally and in written or electronic form, as soon as ERCOT identifies a situation that may lead an insecure condition.

If ERCOT cannot meet applicable reliability standards, ERCOT will discuss the reliability problem with the Single Point Of Contact representing other Resources where Outages are negatively affecting system reliability to reach mutually agreeable solutions, which may include changes to Outage schedules that are agreeable to the Facility Entities.

8.6.3 Deratings

The Resource Entity or its designee must enter material deratings that are expected to last more than forty-eight (48) hours in the ERCOT Outage Scheduler. A derating is considered to be material when the Resource's capability is reduced by the greater of ten percent (10%) or 10 MW due to the loss of auxiliary equipment or other known conditions. ERCOT will consider the Resource's capability as the lesser of the latest seasonal net capability test, or the asset registration submittal.

8.7 Long-Term-Demand Forecasts

ERCOT shall develop and publish monthly on the MIS peak Demand forecasts for each week of the next twelve (12) months. During the development of this forecast, ERCOT may consult with QSEs, TDSPs, and other Market Participants that may have knowledge of potential Load growth.

ERCOT may, at its discretion, publish on the MIS additional peak Demand analyses for periods beyond twelve (12) months.

8.8 Coordination for System Topology Modifications

8.8.1 Coordination with ERCOT

Prior to energizing and placing into service any new or relocated Facility connected to the ERCOT Transmission Grid, TSPs shall coordinate with and receive approval from ERCOT.

8.8.2 Types of Work Requiring Coordination

TSPs shall coordinate with ERCOT the following types of work for any addition, replacement or modification to the ERCOT Transmission Grid:

(1) Transmission lines forming part of the ERCOT Transmission Grid;

(2) Equipment including circuit breakers, transformers, disconnects, reactive devices, and wave traps forming part of the Transmission Facility;

(3) Resource interconnections; and

(4) Protection and control schemes, including Remedial Action Plan (RAP), Supervisory Control And Data Acquisition, Energy Management System, AGC, or Special Protection Schemes (SPS).

8.8.2.1 TSP Information to be provided to ERCOT

The TSP shall notify ERCOT at least thirty (30) days before starting to energize or place into service any new or relocated Facility. The Notice shall be submitted in accordance with formats and procedures adopted by ERCOT and TSPs. For Notices involving co-owned, co-operated, or co-rated Transmission Facilities, the TSP submitting the initial Notice shall communicate with the other Market Participants responsible for co-owning, co-operating, or co-rating said Transmission Facilities prior to the Notice submittal. The Notice shall include the following information:

(1) Proposed energize date;

(2) TSP performing work;

(3) TSP(s) responsible for rating affected transmission element(s);

(4) Location Code if applicable (e.g. station code);

(5) Identification of existing Transmission Facilities involved and new Transmission Facilities (if any) being added or existing Transmission Facilities being permanently removed from service;

(6) Ratings of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(7) Outages required (clearly identify each Outage if multiple Outages are required), including sequence of Outage and estimate of Outage duration;

(8) General statement of work to be completed with intermediate progress dates and events identified;

(9) Supervisory Control and Data Acquisition modification work including descriptions of any new data telemetry points or changes to existing telemetry;

(10) Additional data determined by ERCOT and TSP(s) as needed to complete the ERCOT model representation of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(11) Statement of completion, including:

(a) Statement to be made at the completion of each intermediate stage of project; and

(b) Statement to be made at completion of total project.

(12) Drawings to be attached, including:

(a) Existing status;

(b) For each intermediate stage; and

(c) Proposed completion of job.

8.8.2.2 Approval of the Work

On receipt of the information set forth in Section 8.8.2.1, TSP Information to be provided to ERCOT, ERCOT shall review the information and notify the TSP of any required modifications. ERCOT may, at its discretion, require changes to and more detail regarding the work for the procedure. The requesting TSP will consult with other Entities likely to be affected and will revise the work plan and Notice documentation, 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 TSP, within fifteen (15) days of receipt. Following ERCOT approval, where appropriate, ERCOT shall publish a summary of the approved work on the MIS.

8.8.2.3 Changes to Work Approved by ERCOT

The TSP shall notify ERCOT and any other affected TSPs as soon as practicable of any requested changes to the work plan. ERCOT shall review and approve or reject changes to the work in accordance with Section 8.8, Coordination for System Topology Modifications.

8.8.2.4 Approval of Work Requiring Coordination

ERCOT shall maintain a record of all work approved in accordance with Section 8.8, Coordination for System Topology Modifications, and shall publish information on the MIS regarding each new Transmission Facility to be installed on the ERCOT Transmission Grid.

ERCOT Protocols
Section 9: Settlement and Billing

April 1, 2009

9 SETTLEMENT AND BILLING

9.1 Overview

Settlement is the process used to resolve financial obligations for market services procured through ERCOT for registered Market Participants. Settlement will also assess administrative and miscellaneous fees and provide Transmission Billing Determinants to Transmission and/or Distribution Service Providers (TDSPs).

9.1.1 Settlement Statement Process

ERCOT will produce daily Settlement Statements, as defined in Section 9.2, Settlement Statements, reflecting a breakdown of market charges for hourly and other Settlement Interval Market Services, monthly charges and any annual charges. The Settlement Statement will also reflect administrative and miscellaneous charges.

A Settlement Statement reflecting a negative settlement amount will represent payments to QSE's. A Settlement Statement reflecting a positive settlement amount will represent payments due to ERCOT.

9.1.2 Settlement Calendar

ERCOT will post on the Market Information System (MIS) a Settlement Calendar to denote, for each Operating Day when:

(1) Each scheduled statement will be issued, in accordance with Section 9.2, Settlement Statements;

(2) Each Invoice will be issued, in accordance with Section 9.3, Settlement Invoice;

(3) Payments are due, in accordance with Section 9.4, Payment Process;

(4) Settlement and Billing Disputes for each scheduled Statement must be submitted in order to be considered timely, in accordance with Section 9.5, Settlement and Billing Dispute Process;

(5) ESI ID and Resource ID meter readings are due, in accordance with Section 10.3.3.1, Data Responsibilities;

ERCOT shall notify Market Participants if any of the aforementioned data will not be available in accordance with the Settlement Calendar.

9.2 Settlement Statements

The Settlement Statement(s) will be made available according to the Settlement Calendar for each Operating Day and will be published to the Market Information System (MIS) for Statement Recipients electronically on Business Days. The Statement Recipient is responsible for accessing the information from the MIS once posted by ERCOT. In order to issue a Settlement Statement, ERCOT may use estimated, disputed or calculated meter data and schedule information. An Initial Statement, Final Statement and True-Up Statement will be created for each Operating Day. Resettlement Statements can be created for any given Operating Day, depending on the criteria set forth in Section 9.2.5, Resettlement Statement. When actual validated data and schedule information are available and all of the settlement and billing disputes raised by Statement Recipients during the validation process have been resolved, ERCOT shall recalculate the amounts payable and receivable by the affected Statement Recipient, as described in Section 9.2.5.

For each Qualified Scheduling Entity (QSE), Settlement Statement(s) will denote:

(1) Operating Day,

(2) Statement Recipient's name,

(3) ERCOT identifier (settlement identification number issued by ERCOT),

(4) Status of the Statement (Initial, Final, Resettlement or True-Up),

(5) Statement version number,

(6) Unique Statement identification code, and

(7) Market services settled.

Settlement Statements will break down fees by market services into the appropriate Settlement Interval for that service. When a settlement and billing dispute has been entered for a Settlement Interval, the Settlement Statement will denote the settlement and billing dispute status.

The Settlement Statement(s) will have a summary page of the corresponding detailed documentation.

9.2.1 Settlement Statement Access

All Settlement Statements can be accessed by QSE's electronically via the following methods:

(1) Secured entry on the MIS;

(2) eXtensible Markup Language (XML) access to the MIS.

9.2.2 Settlement Statement Data

Settlement data used to prepare each Settlement Statement will include any available:

(1) Aggregated estimated and actual interval and profiled consumption data for Loads represented by an Load Serving Entity (LSE) by specific Congestion Zones;

(2) Aggregated estimated and actual interval generation data for generation by specific Congestion Zones;

(3) Aggregated estimated and actual interval consumption data for Unaccounted For Energy (UFE) zones (if there are multiple UFE zones);

(4) Resource schedules less Inter-QSE Trades;

(5) Load schedules less Inter-QSE Trades;

(6) Hourly Market Clearing Price for Capacity (MCPC) for each type of Ancillary Service capacity;

(7) Shadow Prices for Replacement Reserve Service (RPRS) capacity purchases;

(8) Market Clearing Price for Energy (MCPE) per Settlement Interval for Balancing Energy services;

(9) Total instructed energy for each Settlement Interval by Congestion Zone and by total ERCOT System;

(10) Hourly Obligations and any self-arranged Obligations for each Ancillary Service;

(11) Adjustments from approved disputes or errors in data components;

(12) Other prices and/or schedules for market services other than Ancillary Services;

9.2.3 Initial Statements

ERCOT will use settlement data, as described in Section 9.2, Settlement Statements, to produce the Initial Statements for each Statement Recipient for the given Operating Day. ERCOT will issue Initial Statements by the end of the tenth (10th) day following the Operating Day. If the tenth (10th) day is not a Business Day, ERCOT will issue the Initial Statement on the next Business Day thereafter.

9.2.4 Final Statements

ERCOT will use settlement data, as described in Section 9.2, Settlement Statements, to produce the Final Statements for each Statement Recipient for the given Operating Day. Final Statements will be issued at the end of the fifty-ninth (59th) calendar day following the Operating Day. In the event that the fifty-ninth calendar day falls on a weekend or holiday, then the Final Settlement Statement will be issued on the following Business Day.

A Final Statement will reflect differences to financial records generated on the previous Settlement Statement for the given Operating Day.

9.2.5 Resettlement Statement

A Resettlement Statement will be produced using corrected settlement data due to resolution of disputes, correction of data errors or a short pay situation, as described in Section 9.4.4, Partial Payments. Any resettlement occurring after a True-Up Statement has been issued must meet the same Interval Data Recorder (IDR) Data Threshold requirements defined in Section 9.2.6, True-Up Statement. The ERCOT Board may, in its discretion, direct ERCOT to run resettlement of any trade day to address unusual circumstances.

Resettlement due to data error will occur when the total of all significant errors in data results in an impact greater than two-percent (2%) of the ERCOT Operating Day market transaction dollars, excluding bilateral transactions. A Resettlement Statement of this sort will be produced as soon as possible to correct the errors. ERCOT will review this percentage on an annual basis. Upon this review, ERCOT may make a recommendation to revise this percentage in accordance with Section 21, Process for Protocols Revision.

Any settlement and billing dispute of Initial Statements resolved in accordance with Section 9.5, Settlement and Billing Dispute Process, will be corrected on the Final Statement for the Operating Day. In the event that a dispute from an Initial Statement on a given Operating Day cannot be resolved by the Final Statement, ERCOT will resolve the dispute on a Resettlement Statement for that Operating Day.

In the event a settlement and billing dispute regarding a Final Statement is submitted within ten (10) Business Days of the Final Statement issuance and is resolved in accordance with Section 9.5 ERCOT shall issue a Resettlement Statement twenty-one (21) Business Days after the Final Statement. This Statement will aggregate all settlement and billing disputes determined valid by ERCOT.

Any dispute of Final Statements resolved in accordance with Section 9.5 will be corrected on the next available Invoice after the Resettlement Statement has been issued. For late settlement and billing disputes resolved in accordance with Section 9.5 and submitted prior to ten (10) Business Days before the True-Up Statement, adjustments will be made on the True-Up Statement. Resolved disputes will be corrected on the next available Invoice run after the True-Up Statement has been issued.

A Resettlement Statement will not be issued less than ten (10) days prior to a scheduled Final or True-Up Statement for the relevant Operating Day. A Resettlement Statement will reflect differences to financial records generated on the previous Statement for the given Operating Day.

9.2.5.1 Notice of Resettlement

While maintaining confidentiality premises of all Market Participants, ERCOT shall post a notice of resettlement on the MIS indicating that a specific Operating Day will be resettled and the date the Resettlement Statement will be issued by ERCOT. 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;

(d) Resettled billable quantity, if known;

(e) Resettled price, if known; and

(f) Total resettled amount, by charge type.

9.2.6 True-Up Statement

ERCOT will use all available settlement data, as described in Section 9.2, Settlement Statements, to produce the True-Up Statement for each Statement Recipient for each given Operating Day.

True-Up Statements will be issued six (6) months following the Operating Day providing at least that ERCOT has received and validated at least ninety-nine percent (99%) of the total number of Electric Service Identifiers (ESI IDs) with a BUSIDRRQ Profile Type code and that ERCOT has received and validated at least ninety percent (90%) of the IDR data from each Meter Reading Entity (MRE) representing at least twenty (20) IDR ESI IDs. If the above conditions have not been met, True-Up Statements will be issued as soon as the IDR data becomes available. If no True-Up Statement has been issued twelve (12) months after the Operating Day, a True-Up Statement will be issued. In the event that any True-Up settlement date does not fall on a Business Day, then the True-Up Statement will be issued on the following Business Day.

A True-Up Statement will reflect differences to financial records generated on the previous Statement for the given Operating Day.

9.2.6.1 Notice of True-Up Settlement Timeline Changes

ERCOT shall post a notice of delay on the MIS of any True-Up settlement indicating that the IDR Data Threshold has not been met.

For any delayed True-Up settlement, ERCOT will post a notice of True-Up settlement on the MIS indicating that a specific Operating Day will be True-Up settled and the date the True-Up Statement will be issued by ERCOT.

9.2.6.2 Validation of the True-Up Statement

Each Statement Recipient shall have the opportunity to review the contents of the True-Up Statement that it receives. With respect to a True-Up Statement, ERCOT will only consider settlement and billing disputes associated with incremental changes between the True-Up Statement and the last Settlement Statement related to that Operating Day. The Statement Recipient shall be deemed to have validated each True-Up Statement unless it has raised a settlement and billing dispute or reported an exception within ten (10) Business Days. Settlement and billing disputes received after ten (10) Business Days will not be accepted. Once validated, a True-Up Statement shall be binding on the Statement Recipient to which it relates, unless ERCOT performs a subsequent resettlement pursuant to this Section.

9.2.6.3 Confirmation

It is the responsibility of each Statement Recipient to notify ERCOT if it fails to receive an Initial Statement, Final Statement, or True-Up Statement on the date specified for issuance of such Settlement Statement in the Settlement Calendar, as defined in Section 9.1.2, Settlement Calendar. Each Statement Recipient shall be deemed to have received its Settlement Statement on the dates specified, unless it notifies ERCOT to the contrary. If ERCOT receives notice that a Settlement Statement has not been received, it will make reasonable attempts to provide the Settlement Statement to the Statement Recipient. The Settlement Calendar will not be modified for a Statement Recipient’s failure to notify ERCOT of a missing Settlement Statement.

9.2.7 Suspension of Issuing Settlement Statements

The Board may direct ERCOT to suspend the issuance of any Settlement Statement to address unusual circumstances. Any proposal to suspend settlements must be presented to Technical Advisory Committee (TAC) for review and comment, in a reasonable manner under the circumstances, prior to such suspension.

9.3 Settlement Invoice

Settlement Invoices will be prepared on a net basis for each Invoice cycle. Invoices will be issued on a weekly basis in accordance with Section 9.1.2, Settlement Calendar. For each cycle, an Invoice Recipient will either be a net payee or net payor. The Invoice Recipient is responsible for accessing the information via the MIS once posted by ERCOT.

Each Invoice Recipient will pay any net debit and be entitled to receive any net credit shown in the Invoice on the payment date, whether or not there is any settlement and billing dispute regarding the amount of the debit or credit.

The payment date will be five (5) Bank Business Days after the Settlement Invoice date. If the payment date does not fall on a Business Day, the Invoice will become due on the next Business Day.

9.3.1 Timing and Content of Invoice

ERCOT will electronically post for each Invoice Recipient, an Invoice based on any Initial Statements, Final Statements, True-Up Statements and Resettlement Statements produced in the last seven (7) days from the prior Settlement Invoice. ERCOT shall post the Settlement Invoices to the Invoice Recipient in accordance with the Settlement Calendar. The Invoice Recipient is responsible for accessing the information from the MIS once posted by ERCOT.

Invoices will be issued on a weekly basis as defined in the Settlement Calendar. Invoice items will be grouped by Initial, Final, Resettlement and True-Up categories and will be sorted by Operating Day within each category. Each Settlement Invoice will contain:

(1) Net Amount Due/Payable – the aggregate summary of all charges owed or due by a QSE summarized by Operating Day;

(2) Time Periods – the time period covered for each line item;

(3) Run Date – the date in which the invoice was created and published;

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

(5) Statement Reference – an identification code used to reference each Settlement Statement invoiced;

(6) Payment Date and Time – the date and time that invoice amounts are to be paid or received;

(7) 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 to which ERCOT shall draw payments due;

(8) Overdue Terms – the terms that would be applied if payments were received late; and

(9) Miscellaneous charges – any late charges or other fees to be applied that are not related directly to market service settlement.

9.4 Payment Process

9.4.1 Overview of Payment Process

Payments shall be made on a Business Day basis in a two-day, two-step process where:

(1) All Settlement Invoices due by close of the Bank Business Day on that day with net funds owed by an Invoice Recipient are paid to ERCOT in immediately available or good funds

(e.g. not subject to reversal) by the Invoice Recipient no later than the first Business Day, and

(2) All Settlement Invoices with net funds owed to an Invoice Recipient are paid by ERCOT to the Invoice Recipient(s) by close of business of the second Business Day.

Payments due to ERCOT, and payments due to Invoice Recipients will be made by Electronic Funds Transfer (EFT) in U.S. Dollars. If paid by ACH, payment must be received by ERCOT at least two (2) Bank Business Days prior to the due date.

9.4.2 Invoice Payments Due ERCOT

Each Invoice Recipient owing monies to ERCOT shall remit the amount shown on its Settlement Invoice no later than the close of the Bank Business Day Central Prevailing Time (CPT) on the relevant payment date.

9.4.3 ERCOT Payment to Invoice Recipients

ERCOT shall calculate the amounts available for distribution to Invoice Recipients no later than the next Business Day following the payment date and shall give irrevocable instructions to the ERCOT financial institution to remit to the Invoice Recipients for same day value the amounts determined by ERCOT to be available for payment. ERCOT shall make such payments no later than the close of the Bank Business Day Central Prevailing Time on the next Business Day following payment date.

9.4.4 Partial Payments

In the event one or more Invoice Recipient(s) owing monies did not pay in full (short payment) ERCOT will follow the procedure set forth below:

(1) ERCOT will make every reasonable attempt to collect payment from the short-paying Invoice Recipient(s) prior to one hour preceding the close of the Bank Business Day CPT on the day that the payment by ERCOT is disbursed to the Invoice Recipient(s).

(2) ERCOT will draw on any available security pledged to ERCOT by the QSE(s) who did not pay the amount due.

(3) ERCOT will offset or recoup any amounts owed or to be owed from ERCOT to a short paying Invoice Recipient against amounts short paid by that Invoice Recipient, and ERCOT will apply the amount offset or recouped to cover payment shortages.

(4) If, after taking the actions set forth in items (2) and (3), above, ERCOT still does not have sufficient funds to pay all amounts in full (total short pay amount), ERCOT will deduct ERCOT administrative fees as specified in Section 9.7, Administrative Fees, and payments for RMR Services from the amount received or collected and then reduce

payments to all Invoice Recipients owed monies from ERCOT except for monies owed for RMR Services. The reductions will be based on a pro rata basis of monies owed to each ERCOT creditor, for services other than RMR Services, in the settlement process for each Settlement Invoice to the extent necessary to clear ERCOT's accounts to the extent possible on the payment date to ensure revenue neutrality for ERCOT. ERCOT shall provide to all QSEs payment details on all short payments and subsequent reimbursements of short pays. Details will include the identity of and dollar amount attributable to each short-paying QSE and dollar amounts broken down by Invoice numbers. In addition, ERCOT shall provide the total amount due to the Market Participants prior to applying the short pay and the short pay amount on the Invoice.

(5) One hundred eighty (180) days following a short pay occurrence, if sufficient funds continue to be unavailable for ERCOT to pay all amounts in full (excluding interest or late fees) to short paid Entities, and the short paying Entity is not in compliance with a payment plan designed to enable ERCOT to pay all amounts in full (excluding interest or late fees) to short paid Entities, the total short pay amount, less the total payments expected from a payment plan, will be collected from the QSEs representing LSEs, on a Load Ratio Share basis, using the Load Ratio Share for the calendar month three (3) months prior to the date on which the Invoice is issued, and paid to the QSEs that were previously short paid. ERCOT will cease charging Late Fees to the default Entity when the conditions initiating Uplift are met. Any uplifted short payment amount greater than two and one half million dollars ($2,500,000) shall be scheduled such that two and one half million dollars ($2,500,000) is charged on each set of invoices until the total short payment amount is uplifted. Short pay Invoices shall be issued at least thirty (30) days apart from each other. Payments will be due on the date specified on the short pay Invoice. Any short and late payments will be handled pursuant to Section 9.4.4, Partial Payments and 9.4.6, Late Fees, respectively.

(6) Upon the entrance of a payment plan with a short pay Entity, ERCOT will post to the ERCOT website:

(a) the short pay plan;

(b) the schedule of quantifiable expected payments; and

(c) the Invoice dates to which the payments will be applied. The schedule will be updated when or if modifications are made to the payment schedule.

(7) To the extent ERCOT is able subsequently to collect past due funds owed by a short paying Entity, ERCOT shall allocate such funds as are collected to the earliest Invoice for which that Entity remains a short payer. ERCOT shall use its best efforts to distribute past due funds on a pro rata basis of monies owed on the next Business Day after receipt of the monies, when sufficient funds for the relevant Operating Day are available in this settlement process.

9.4.5 Enforcing the Security of a Defaulting QSE

ERCOT will make reasonable efforts to enforce the security of the defaulting Invoice Recipient (pursuant to Section 16.2.9, Payment Breach and Late Payments by Market Participants) to the extent necessary to cover the default amount. QSEs shall restore the level of their security in accordance with Section 16, Registration and Qualification of Market Participants of these Protocols.

9.4.6 Late Fees

The defaulting Invoice Recipient shall pay late fees ("Late Fees") to ERCOT on the default amount for the period from and including the date on which the payment was originally due through the date on which ERCOT receives the payment, together with any related costs incurred by ERCOT. ERCOT shall calculate Late Fees based on the ERCOT Fee Schedule. ERCOT will cease charging Late Fees to the default Entity when the conditions initiating Uplift in Section 9.4.4(5) are met.

ERCOT shall distribute to the short-paid Entities, on a pro rata basis of monies owed to each such Entity, any Late Fees collected from the short-paying Entity less ERCOT's costs. If no Entities were short paid, ERCOT will apply the Late Fees collected to the Equalization Adjustment described in Section 9.6.2, Equalization Adjustment.

9.5 Settlement and Billing Dispute Process

9.5.1 Data Review, Validation, Confirmation and Dispute of Settlement Statements

Statement Recipients and Invoice Recipients are responsible for the review of their Settlement Statements and Settlement Invoices to verify the accuracy of the settlement data, as defined in Section 9.2, Settlement Statements used to produce the Settlement Statement and Settlement Invoice. Statement Recipients and Invoice Recipients must submit any dispute related to Settlement Statement or Settlement Invoice data according to this Section 9.5, Settlement and Billing Dispute Process.

9.5.2 Notice

A Statement Recipient or Invoice Recipient may dispute items or calculations set forth in its Initial Statements, Final Statements, or Resettlement Statements. If the Statement or Invoice Recipient wishes to dispute any of these items or calculations, it will register the settlement and billing dispute with ERCOT by electronic means within ten (10) Business Days from the date of issue of the respective Settlement Statement or Settlement Invoice. However, to the extent that the disputing party reasonably demonstrates that the settlement or billing dispute relates to information made available in accordance with Section 1.3.3, Expiration of Confidentiality, then the disputing party must register the settlement or billing dispute with ERCOT by electronic means within sixty (60) days from the date that the information becomes available. All communication to ERCOT and from ERCOT concerning disputes will be through the MIS.

ERCOT will not accept settlement and billing disputes within ten (10) Business Days prior to the True-Up Statement. Disputes submitted late will not be considered for the Resettlement Statement for the Operating Day, but rather will be considered for resolution by the True-Up Statement for the Operating Day. For disputes relating to a True-Up Statement, only settlement and billing disputes associated with incremental changes between the True-Up Statement and the last Settlement Statement related to that Operating Day will be considered by ERCOT unless the disputing party reasonably demonstrates that the dispute relates to information made available in accordance with Section 1.3.3, Expiration of Confidentiality.

9.5.3 Contents of Notice

The notice of settlement and billing dispute will state clearly:

(1) Disputing organization;

(2) Dispute contact person;

(3) Dispute contact information;

(4) Operating Day in dispute;

(5) Statement identification code or Settlement Invoice reference number;

(6) Statement type;

(7) Market Service type;

(8) Time period in dispute;

(9) Amount in dispute;

(10) Settlement and billing dispute type; and

(11) Reason(s) for the dispute.

Each settlement and billing dispute shall be specific to an Operating Day and a market service type. If a condition that causes a dispute affects multiple Operating Days or market service types, a separate dispute form must be entered for each market service type and/or Operating Day affected.

Forms for entering a settlement and billing dispute shall be provided on the MIS.

The settlement and billing dispute must be submitted to ERCOT with all available evidence reasonably required to support the claim.

Notices will be submitted via an ERCOT approved electronic format. The Statement Recipient or Invoice Recipient will receive a dispute tracking identifier from ERCOT.

9.5.4 ERCOT Processing of Disputes

ERCOT shall determine if the settlement and billing dispute is timely and complete by verifying that the dispute was submitted within the specified time and contains at least the minimum required information. ERCOT shall make reasonable attempts to remedy any informational deficiencies by working with the Statement Recipient or Invoice Recipient.

Except for disputes related to a True-Up Statement, ERCOT will further make reasonable attempts to process settlement and billing disputes that are provided late. ERCOT will place priority on processing on-time disputes. ERCOT will issue a settlement and billing dispute resolution report containing information related to the disposition of granted settlement and billing disputes.

Each dispute will have a status as defined in the following paragraphs. Valid status designation include:

(1) Open,

(2) Denied,

(3) Closed,

(4) Granted, or

(5) Granted with Exceptions.

A settlement and billing dispute will be deemed Open when the Statement or Invoice Recipient submits a timely and complete dispute to ERCOT.

Any settlement an billing disputes determined by ERCOT to be missing required information as defined in Section 9.5.3, Contents of Notice will be Denied and will be returned to the Statement Recipient or Invoice Recipient with an explanation of the missing data. An Invoice Recipient or Statement Recipient will be able to resubmit the dispute with additional information in accordance with Section 9.5.2, Notice. Once the Market Participant sends all required information and ERCOT determines the settlement and billing dispute is timely and complete, the dispute status will be considered Open.

ERCOT will determine a settlement and billing dispute is Denied if ERCOT concludes that the information used in the Settlement Statement or Invoice is correct. ERCOT will notify the Statement or Invoice Recipient when a settlement and billing dispute is Denied, and will document the supporting research for the denial.

If the Statement Recipient or Invoice Recipient is not satisfied with the outcome of a Denied settlement and billing dispute, the Statement or Invoice Recipient may proceed to Alternative

Dispute Resolution (ADR) as described in Section 20, Alternative Dispute Resolution of these Protocols. If after forty-five (45) days from receiving notice of a Denied dispute, the Statement Recipient or Invoice Recipient does not begin ADR, the dispute will be Closed.

ERCOT may determine a settlement and billing dispute is Granted. ERCOT will notify the Statement Recipient or Invoice Recipient of the resolution, and will document the basis for resolution. Upon resolution of the issue, the settlement and billing dispute will be processed on the next available Settlement Statement for the Operating Day. Once the necessary adjustments appear on the next available Settlement Statement, the settlement and billing dispute is then Closed.

ERCOT may determine a settlement and billing dispute is Granted with Exceptions when the information is partially correct and ERCOT will provide the exception information to the Statement Recipient or Invoice Recipient. ERCOT will require an acknowledgement from the Statement Recipient or Invoice Recipient of the dispute Granted with Exceptions within ten (10) Business Days. The acknowledgement must indicate acceptance or rejection of the documented Exceptions to the dispute. If accepted, ERCOT will post the necessary adjustments on the next available Settlement Statement for the Operating Day and will change the dispute status to Closed. If ERCOT does not receive a response from the Statement Recipient or Invoice Recipient within ten (10) Business Days, the dispute will be considered accepted and Closed.

If a dispute, which is Granted with Exceptions, is rejected by the Invoice Recipient or Statement Recipient, the dispute will be investigated further. After further investigation, if the settlement and billing dispute is subsequently Granted, the dispute will be processed on the next available Statement to be issued. The dispute is then Closed. If exceptions to the dispute still exist, the Statement Recipient or Invoice Recipient may either accept the dispute for resolution as Granted with Exceptions, or begin ADR according to Section 20, Alternative Dispute Resolution of these Protocols.

ERCOT will make all reasonable attempts to resolve all Open disputes relating to all Settlement Statements within ten (10) Business Days after the settlement and billing dispute due date as specified in the Settlement Calendar. ERCOT will post the necessary adjustments for resolved settlement and billing disputes on the next Resettlement, Final or True-Up Settlement process.

For settlement and billing disputes requiring complex research or additional time for resolution, and late disputes that can be reasonably processed, ERCOT will notify the Invoice Recipient or Statement Recipient of the length of time expected to research and post those disputes through research and, if a portion or all of the dispute is granted, ERCOT will post the necessary adjustments on the next available Settlement Statement for the Operating Day, if any portion or all of the dispute is Granted. Statement or Invoice Recipients have the right to proceed to the ADR process in Section 20, Alternative Dispute Resolution of these Protocols for timely filed disputes that cannot be resolved through the settlement and billing dispute process contained in this Section 9.5.

9.5.5 Settlement of Emergency Interruptible Load Service

(1) ERCOT shall settle each EILS Time Period in an EILS Contract Period on the Final Settlement Statement that is posted ten (10) days after the final settlement of the last Operating Day of the EILS Contract Period is posted, as described in Section 9.2.4, Final Statements. If the tenth (10^{th}) day is not a Business Day, ERCOT will issue the EILS settlement on the next Business Day thereafter. All disputes for the settlement of the EILS Contract Period are due ten (10) Business Days after the date that the EILS settlement was posted. ERCOT shall resolve any approved disputes upon resettlement of the EILS Contract Period, as described in Section 9.5.5(2).

(2) ERCOT shall resettle each EILS Time Period in an EILS Contract Period on the True-Up Statement for the Operating Day on which the charge first settled as described in Section 9.5.5(1). ERCOT shall resolve any approved disputes no later than thirty (30) Business Days after the date that the EILS resettlement was posted.

9.5.6 Disputes for Operational Decisions or Market Rules

Statement Recipients or Invoice Recipients may not dispute a Settlement Statement or Invoice due to an ERCOT operational decision or market rule, unless it is alleged that the decision violated these Protocols. Inquiries or disputes concerning ERCOT operational decisions, Protocols, or Operating Guides must be handled through the Protocol change process set forth in Section 21, Process for Protocols Revision.

9.6 Settlement Charges

The Settlement calculations are contained in Sections 6, Ancillary Services, Section 7, Congestion Management and Section 9, Settlement and Billing of these Protocols. ERCOT will publish a market service type matrix to the MIS that summarizes each market service by ID, description and allocation.

9.6.1 Balancing Energy Neutrality Adjustment

Any dollar disparity between Load Imbalance, Resource Imbalance, Mismatched Schedule Payments, Mismatched Schedule Charges, TCR Payments, CSC costs, and any charge resultant from Uninstructed Deviations will be allocated to Load Serving Entities on a Load Ratio Share for each interval to ensure revenue neutrality of the imbalance market. The net dollar amount could be negative or positive.

To determine the Balancing Energy Neutrality Allocation for a QSE, take the sum of the Resource Imbalance, Load Imbalance, Uninstructed Resource Charge, Mismatched Schedule Payments, Mismatched Schedule Charges, payments to TCR account holders, and the total Balancing Energy CSC costs; and multiply this amount by the Load Ratio Share of that QSE for the given interval.

$$\mathbf{BENA_{iq}} \quad = \quad \mathbf{-1 * (\Sigma\ (RI_{iz} + LI_{iz} + URC_{iz} + MISD_{iz} + MISR_{iz})_z + TCRPAY_{Bei} + \Sigma\ CSC_{Bei}\ ) * LRS_{iq}}$$

$$TCRPAY_{Bei} \quad = \quad -\ \Sigma\ (TCRcsc_i\ ) / 4 * SP_{CSCi}\ )_{CSC}$$

Where:

$BENA_{iq}$	Balancing Energy Neutrality Adjustment collected from the QSEs in that interval
CSC_{BEi}	The total Balancing Energy CSC costs per interval for all QSEs
LI_{iz}:	Load Imbalance per interval, per zone
LRS_{iq}	QSE Load Share relative to total Load in that interval
$MISD_{iz}$	Mismatched schedule payments for the mismatched amounts delivered to ERCOT, per interval, per zone
$MISR_{iz}$	Mismatched schedule charges for the mismatched amount received from ERCOT, per interval, per zone
RI_{iz}:	Resource Imbalance per interval, per zone
SP_{CSCi}	Energy Shadow Price per CSC per interval
TCR_{CSCi}	Total number of TCRs per CSC for interval, i
$TCRPAY_{Bei}$	Payment to the TCR Account Holder per interval
URC_{iz}	Uninstructed Resource Charge per interval per zone

9.6.2 Equalization Adjustment

The Equalization Adjustment will be a charge or payment uplifted to Load. This adjustment will take place daily. Any imbalances from all debits and credits at the end of the operating day will be allocated based on Load Ratio Share. The Equalization Adjustment can be positive or negative.

Any market transaction that cannot be associated with a cost recovery or payment scheme, to one or more specific QSE's, will be uplifted to Load according to Load Ratio Share. This adjustment could be positive or negative.

$$\mathbf{EA_{dq}} \quad = \quad \mathbf{-1 * (AMT * LRS_{dq})}$$

Where:

EA_{dq}	Equalization Adjustment of the QSE for the day
AMT	Net Dollars of the day to be paid – Net Dollars of the day to pay
LRS_{dq}	That day's Load Ratio Share of that QSE

9.7 Administrative Fees

Administrative Fees, as described in this Section 9.7, Administrative Fees, shall be determined by the ERCOT Board and posted on the Market Information System.

9.7.1 ERCOT System Administration Fee

(1) The ERCOT System Administration Fee is a fee based upon the fee factor approved by the ERCOT Board and the Public Utility Commission of Texas (PUCT) to support ERCOT activities subject to PUCT oversight.

(2) ERCOT shall calculate the ERCOT System Administration Fee by multiplying total Load by the Load fee factor. The fee factor will not change during a Settlement Interval. The ERCOT System administration fee will be a separate Market Service on the Settlement Statement.

(3) The ERCOT System Administration Fee will be charged to a Qualified Scheduling Entity (QSE) on a daily basis, broken down by the appropriate quantity per Settlement Interval. For purposes of the ERCOT System Administration Fee, QSE Load will include losses, Direct Current (DC) Tie exports and approved netting. QSE Load will be aggregated to the QSE level, and not by Congestion Zone. The ERCOT System Administration Fee is not a revenue neutral fee.

(4) The calculation of the ERCOT System Administration Fees is as follows:

$$\mathbf{QAF_{iq} = EAF * (AML_{iq} + X_{iq})}$$

Where:

QAF_{iq}	QSE administration fee per interval
AML_{iq}	Adjusted Metered Load (AML) in MW per interval for the given QSE
X_{iq}	Deemed actual exported quantity per interval per QSE (adjusted for transmission losses and Unaccounted For Energy (UFE))
EAF	ERCOT Admin Fee factor ($/MWh)

9.7.2 Renewable Energy Credit Administration Fee

[Reserved]

9.7.3 Mismatched Schedule Processing Fee

There is a flat fee for a QSE submitting a mismatched schedule. The fee factor will not change during a Settlement Interval. All mismatched schedules will be assessed a charge, even if the mismatch is the result of an error made by another QSE through a bilateral agreement.

The indicator will be on an interval basis and should either have a value of 1 for mismatch or 0 for no mismatch at each interval.

This mismatched scheduling processing fee is a not a revenue neutral fee, as it is the amount collected by ERCOT to administer the market. The mismatched fee will be included as a Market Service on the Settlement Statement.

$$\mathbf{MSFQ_i} \quad = \quad \mathbf{\sum (MSFF_i * QMS_i)}$$

Where:

i	interval being calculated
$MSFQ_i$	Mismatched Schedule Fee for QSE per interval
$MSFF_i$	Mismatched Schedule Fee Factor per interval
QMS_i	QSE Mismatched Schedule Indicator per interval (value = 0 or 1, where 1 = mismatched and 0 = matched)

9.7.4 Market Participant Application Fee

A fee collected as part of the application process, in accordance with Section 16, Registration and Qualification of Market Participants, of these Protocols.

9.7.5 Private Wide Area Network Fees

Market Participants connected to the Wide Area Network (WAN) shall be assessed a one-time installation fee and monthly maintenance fees related to access to the WAN as approved by the ERCOT Board. This fee is separate from the administrative fee.

9.7.6 ERCOT Nodal Implementation Surcharge

ERCOT shall calculate the nodal implementation surcharge (“NIS”) by multiplying total net metered generation by a nodal surcharge factor. The nodal surcharge factor will be a flat rate as authorized by the PUCT. The NIS will appear as a separate market service on the Settlement Statement. ERCOT shall charge the NIS on a daily basis to QSEs representing Generation Resources, broken down by the appropriate quantity per Settlement Interval. QSE total net metered generation will be the total of the net metered generation aggregated to the QSE level. ERCOT will charge the NIS until it has recovered the full cost of implementing the nodal market redesign, at which time the NIS will end. The NIS is not a neutral fee, as it is the amount ERCOT collects to fund implementation of the nodal market redesign.

$$\mathbf{QNS_{iq}} \quad = \quad \mathbf{NODSF * MR_{iq}}$$

Where:

QNS_{iq}	QSE NIS per interval ($)
MR_{iq}	Real-Time net metered generation in MWh per interval for the given QSE
NODSF	Nodal surcharge factor ($/MWh)

i	15 minute Settlement Interval being calculated
q	QSE

9.8 Transmission Billing Determinant Calculation

ERCOT will provide the market with the determinants defined below to facilitate billing of Transmission access service. ERCOT will not be responsible for billing, collection or dispersal of payments associated to Transmission access service.

9.8.1

ERCOT shall calculate and provide to Market Participants via MIS the following data elements annually to be used by TDSPs as billing determinants for Transmission access service. This data shall be provided by December 01 of each year. This calculation shall be made in accordance with the requirements of the PUCT. The data used to perform these calculations shall come from the same system(s) used to calculate settlement-billing determinants used by ERCOT:

(1) The 4-Coincident Peaks (4-CP) for each TDSP, as applicable.

(2) The ERCOT average 4-CP.

(3) The average 4-CP for each TDSP, as applicable, coincident to the ERCOT average 4-CP.

Average 4-CP is defined as "the average Settlement Interval coincidental MW peak occurring during the months of June, July, August, and September."

Settlement Interval MW coincidental peak is defined as "the highest monthly 15 minute MW peak for the entire ERCOT Transmission Grid as captured by the ERCOT settlement system."

9.8.2 Direct Current Tie Schedule Information:

(1) By the seventh (7th) working day of each month, ERCOT shall provide the requesting TDSP data pertaining to transactions over the DC Ties for the immediately preceding month. For each transaction, the following NERC tag data will be provided, at a minimum:

- NERC Tagging identifier (Tag Code)
- Date of transaction; start and stop times
- Megawatt-hours (MWH) actually transferred
- Sending Generation Control Area (GCA)
- Receiving Load Control Area (LCA)

- Purchasing / Scheduling Entity (PSE)
- Entity scheduling the export of power over a DC Tie
- Status of Transaction (Implement, Withdrawn, Cancelled, Conditional, etc.)
- (2) ERCOT shall maintain and provide the requesting TDSP data pertaining to transactions over the Direct Current Ties for the period from June 2001 to the present. For each transaction, the same data as specified in Section 9.8.2 (1) will be provided.

9.9 Profile Development Cost Recovery Fee for a Non-ERCOT Sponsored Load Profile Segment

PUCT Project 25516, Load Profiling and Load Research Rulemaking, §25.131 (e) (3), requires ERCOT to establish and implement a process to collect a fee from any REP who seeks to assign customers to a non-ERCOT sponsored profile segment. The process shall include a method for other REPs who use the profile segment to compensate the original requester of the new profile segment and for ERCOT to notify TDSPs which REPs are authorized to use the new profile segment. This profile development cost recovery fee is overseen by ERCOT.

Within thirty (30) days after a profile segment has received 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 will be available for review by any Market Participant. Any costs submitted more than thirty (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 twenty-four (24) months preceding the original submission date of the profile segment change request, and are further limited to:

(1) Costs for Load research as paid to TDSPs and/or ERCOT, documented by a copy of all TDSP or ERCOT invoices or other evidence of payment, including but not limited to:

(a) Buying and installing IDR meters;

(b) Installing communication equipment such as phone lines or cell phones; and,

(c) Reading the meters and translating the data.

(2) Reasonable costs paid to third parties, including a copy of all third-party invoices or other documentary evidence of payment, including but not limited to:

(a) Defining the request such as identifying population, profile, data, etc.;

(b) Preparing the request such as collecting and analyzing data and presenting the case; and,

(c) Undertaking the review process such as meeting with ERCOT staff, Profiling Working Group (PWG), Retail Market Subcommittee (RMS), TAC, and the ERCOT Board.

(3) Requestor's reasonable internal documented costs itemizing all persons, hours, and other expenses associated with developing the request per items 1 and 2, above.

Within sixty (60) days after a profile segment has received final approval from ERCOT, ERCOT staff shall evaluate the costs submitted and disallow any costs not meeting these criteria. The remaining costs will comprise the total reimbursable cost. Within the same sixty (60) day period, ERCOT shall post a report on the ERCOT website summarizing the allowed expenses by items 1 through 3 above. If a Market Participant, including the requestor, disagrees with the ERCOT staff ruling with respect to the total reimbursable cost, the Market Participant may submit a dispute as outlined in Section 20, Alternative Dispute Resolution Procedures. No disputes may be submitted after forty-five (45) days from posting of the total reimbursable cost to the ERCOT website.

The fee is calculated as follows:

If a REP is the requestor, then:

$$\text{FEE} = \$C / n$$

Where:

n:	the number of REPs subscribing to the profile segment
$C:	the total reimbursable cost

If the requestor is not a REP, then:

$$\text{FEE} = \$C / (n + 1)$$

The fee shall 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.

Beginning four (4) years after the date on which the profile segment becomes available for settlement, any REP may request assignment of ESI IDs to the profile segment without being assessed the profile development cost recovery fee.

ERCOT Protocols
Section 10: Metering

May 1, 2009

10 METERING

10.1 Overview

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.

Transmission and/or Distribution Service Providers (TDSP) 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 TDSPs and must collect data from all ERCOT-Polled Settlement (EPS) Meters.

All Service Delivery Points (SDPs), excluding EPS, generation, or Non Opt-In Entity (NOIE) metering points, that meet the requirements of PUCT Substantive Rule 25.311 are eligible for competitive meter ownership pursuant to such PUCT Substantive Rule. All competitively owned meters shall meet all the applicable metering requirements of the ERCOT Protocols and Competitive Metering Guides.

10.2 Scope of Metering Responsibilities

10.2.1 QSE Real-Time Metering

The QSE's responsibility for Real-Time metering requirements for Ancillary Service verification is contained in Section 6.5.1.1, General Technical Requirements.

10.2.2 TDSP Metered Entities

TDSPs are responsible for supplying ERCOT with meter data associated with:

(1) All Loads using the ERCOT System;

(2) Any Generation Resource that delivers less than ten (10) MW to the ERCOT System and that is connected directly to the distribution system; a TDSP 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:

  (a) generation owned by a NOIE and used for NOIE's self-use (not serving Customer Load); and

  (b) renewable generation with a design capacity less than fifty (50) kW interconnected to a TDSP and not registered as a Generation Resource; and

(3) NOIE points of delivery where metering points are radial Loads and are unidirectionally metered. The TDSPs have the option of making some or all such meters EPS compliant and to request that ERCOT poll the meters.

Each TDSP is responsible for the following:

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

(2) 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;

(3) 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 Resource. These incremental costs shall be borne by the Entities requesting the service pursuant to the TDSP's tariffs; and

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

10.2.3 ERCOT Polled Settlement Meters

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

(1) Generation connected directly to the ERCOT Transmission Grid;

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

(3) Generation delivering ten (10) MW or more to the ERCOT System;

(4) Generation participating in any Ancillary Service market;

(5) NOIE points connected bi-directionally to the ERCOT system; and

(6) Direct Current Ties.

Additionally, ERCOT shall poll any generator 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. Loads acting as a Resource of ten (10) MW or more on the ERCOT System may, at their option, have an EPS meter.

10.2.3.1 Entity ERCOT Polled Settlement Responsibilities

The following defines the responsibilities of Entities regarding EPS metering:

(1) 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;

(2) TDSPs shall have EPS Metering Facilities installed and maintained under the supervision of a TDSP "EPS Meter Inspector," which is defined as an employee or agent of the TDSP who has received EPS training from ERCOT, and is described further herein;

(3) TDSPs 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 the SMOG;

(4) TDSPs shall install and maintain "Back-up Meters" 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;

(5) Costs incurred in the installation and maintenance of EPS metered Facilities and communications will be the responsibility of the TDSP 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 TDSP's tariffs; and

(6) Specific operating practices for EPS Metering Facilities are included in the SMOG.

10.3 Meter Data Acquisition System (MDAS)

10.3.1 Purpose

The MDAS will be used:

(1) 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 and/or Distribution Service Provider (TDSP) for settlement and billing purposes; and

(2) 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

Each TDSP shall, in accordance with these Protocols and the Settlement Metering Operating Guides (SMOG), provide ERCOT approved metering communication equipment and connection to permit ERCOT access to the TDSP's EPS Meters.

ERCOT shall retrieve meter data electronically and automatically by MDAS. ERCOT may also collect meter data on demand.

10.3.2.1 Generation Meter Splitting

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 (2) or more virtual generating units for a Generation Entity. Each Generation Entity representing a virtual generating unit may have its energy and capacity scheduled through separate QSEs. 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 Resources such as wind and solar generation.

When the Generation Resource unit is registered with ERCOT, the Entities representing virtual generator units shall be required to submit a percentage allocation of the Resource to be used to determine the capacity available at each virtual generator unit.

When the generator unit is registered with ERCOT, the owners of the unit shall submit all required ERCOT Facility registration documentation and an ERCOT-approved splitting agreement executed by an Authorized Representative from each owning Entity. Such agreement shall contain a defined and fixed ownership percentage as among the owning Entities. ERCOT shall establish this generator as a "split," essentially establishing a virtual generator meter. Generation splitting based on a static ratio is not permitted. Generation splitting requires Real-Time splitting signals.

10.3.2.1.1 Generator Metering Real-Time Splitting Signal

When the split-metered generating unit is registered at ERCOT, the Entities representing the virtual generator units shall select one master QSE to provide ERCOT with a Real-Time signal of the MW of generation per virtual generator unit. The signal must be sent from the master QSE's Energy Management System (EMS) system to ERCOT via the appropriate telemetry. The signal must be revised every scan cycle and must represent each virtual generator unit in positive MW. The signal must contain the Resource ID (RID) and the MW assigned to that RID.

ERCOT shall integrate the signals and provide a MWh value for each 15-minute interval for each virtual generator unit. The settlement system must use the MWh per interval value to calculate the percentage breakdowns to be applied to the actual metered MWh values retrieved from the EPS metered Entity.

10.3.2.1.2 Allocating ERCOT Polled Settlement Metered Data to Generator Virtual Meters

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 virtual generator ratios applied to assign the generation to the QSE representing each owner of the virtual generators. The MWh quantities of the virtual generators must be used in all settlement calculations and reports.

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 Splitting Signal

For any interval when ERCOT has not received a Real-Time signal for any one of the virtual generating units, 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 Virtual Generator Ratio

For split-metered generating units, 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.

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 Generation Splitting Data made available to Market Participants

Market participants shall have access to allocated generation output and ratio data only for virtual generators that they represent. ERCOT shall provide the allocation ratio for that RID. The master QSE for a split-metered generator unit shall have access to the allocation ratios and assigned generation output for units in which they act as the master QSE.

10.3.2.1.6 Allocating ERCOT Polled Settlement Metered Data to Generator Owners When it is Net Load

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 ERCOT Polled Settlement Meter Data

Where the EPS Meter is not located at the point of interconnection to the ERCOT Transmission Grid, actual metered consumption must be adjusted for line and transformation losses to the point of interconnection. The preferred method for loss compensation and correction is via internal meter programming.

Recognizing the fact that some locations may not have the total functionality necessary to perform internal compensation, the MDAS 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.

No meter may be compensated internally for losses more than once. ERCOT may compensate multiple meters prior to netting to the point of interconnection. Pulse communications transfer of data between meters is not allowed.

10.3.2.3 Generation Netting for ERCOT Polled Settlement Meters

At Generation Resource Facilities, generation and associated Loads, including construction and maintenance Load that is netted with existing generation auxiliaries, must be metered at their points of interconnection to the ERCOT Transmission Grid. Interval Data Recorder (IDR) meters 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.

For settlement purposes, generation netting is not allowed except under one of the following conditions:

(1) Single point of interconnection with delivered and received metering data channels;

(2) Multiple points of interconnection where the Loads and generator output are electrically connected to a common switchyard, as defined below. In addition, there must be sufficient generator capacity to serve all plant Loads for netting to occur;

(3) A Qualifying Facility (QF) with point(s) of interconnection where the QF is selling to the QF's thermal host(s) may net the Load meters of the thermal host with its 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 TDSPs may install monitoring equipment necessary for measuring Load to determine stranded cost charges, if any are applicable, as determined under the Public Utility Regulatory Act, Title II, TEX UTIL. CODE ANN. (Vernon 1998 & Supp. 2007) (PURA) and applicable Public Utility Commission of Texas (PUCT) rules. If the PUCT requires other Load served by onsite generators to pay the System Benefit Fund charges, then, in instances in which Load is served by generation through a common switchyard, the TDSP may install metering equipment solely for purposes of the TDSP's calculation of System Benefit Fund charges, as provided by PURA, if any is applicable. For purposes of this Section, new on-site generation has the meaning as contained in PURA §§ 39.252 and 39.292(k); or

(4) For Generation Resources and/or Load with flow-through on a private, contiguous transmission system (not included in a TDSP 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, the metered interconnection points must be assigned to the same Congestion Zone and Unaccounted For Energy (UFE) zone.

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

10.3.2.4 Reporting of Net Generation Capacity

All Generation Resource Facilities with associated Load shall report to ERCOT before February 1st of each year their projected Net Generation capacity available to the grid for use by others during the June to August time period for the current calendar year and five (5) subsequent years in the same format as the generation capacity reports provided to the PUCT.

10.3.3 TDSP Metered Entities

10.3.3.1 Data Responsibilities

TDSPs shall be responsible for the following:

(1) 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;

(2) Providing start date, stop date, ESI ID or RID, and consumption data in kWh as well as an identifier for "estimated" reads as applicable;

(3) 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 TDSP tariffs or for CR Customer billing. If the CR and TDSP do not require a Demand value, then the TDSP shall not submit a Demand value to ERCOT even if the meter has a Demand register;

(4) Validation, Editing, and Estimation of meter data (VEE) according to the standards in this Section before submitting data to the settlement process;

(5) 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 TDSP approved tariffs; and

(6) Metering all Loads, unless the Load meets one of the following criteria:

   (a) Energy consumption by substation Facilities and equipment for the purpose of transporting electricity (e.g., substation transformers, fans, etc.);

   (b) Unmetered energy consumption represented by an ERCOT-approved Load Profile; or

   (c) Energy charge and discharge and associated losses for the Presidio substation Facilities, for the ERCOT Board approved storage devices installed as part of a transmission reliability project.

10.3.3.2 Retail Load Meter Splitting

Retail Service Delivery Points (SDP) with Loads above one (1) MW may split their actual meter data into a maximum of four (4) 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

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 (4) 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:

(1) The signal splitter may be programmed to split the Load in any way the Customer chooses, provided that such splitting results in positive Load;

(2) 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;

(3) The TDSP shall be responsible for approving the specifications and installation of any signal splitting devices;

(4) IDRs shall be required on the master Customer Load meter and each of the split channels for verification and settlement purposes;

(5) The TDSP metering system recording such split signals (four (4) ESI IDs) may be required to be redundant if so provided by TDSP tariffs;

(6) The split signals must be recorded in Real Time and cannot be altered or substituted later in time;

(7) One (1) Entity shall be designated to pay the total TDSP charges for the Customer; and

(8) 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 TDSP 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 TDSP. Each ESI ID may be assigned to a separate CR. The master meter may not be assigned an ESI ID.

(2) The TDSP shall send interval data for each ESI ID for the ERCOT settlement system.

(3) The TDSP 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

Settlement Quality Meter Data shall be submitted to ERCOT on a periodic cycle, but no later than monthly, using the Texas Standard Electronic Transaction (TX SET) meter data exchange format. Each TDSP shall ensure that consumption meter data submitted to ERCOT is in intervals of:

(1) 15-minutes for those ESI IDs and RIDs served by IDRs; and

(2) Monthly or on an ERCOT-approved meter reading cycle for non-IDR meters.

The Settlement Quality Meter Data submitted by TDSPs must be in kWh and kVarh values (as applicable).

[PRR766: Replace Section 10.3.3.3 above with the following upon system implementation:]

(1) Settlement Quality Meter Data shall be submitted to ERCOT on a periodic cycle, but no later than monthly:

(a) For provisioned Advanced Meters, Settlement Quality Meter Data will be submitted using an ERCOT specified file format for the interval data only, which will be used for settlement.

In addition, the monthly non-interval or total consumption values for these ESI IDs shall be provided to ERCOT and Load Serving Entities (LSEs) using the appropriate Texas Standard Electronic Transaction(s) (TX SET) in order to effectuate the registration transactions outlined in Section 15, Customer Registration. These non-interval or total consumption values will not be used for settlement.

(b) For all other meters, Settlement Quality Meter Data will be submitted using the appropriate TX SET transaction.

(2) Each TDSP 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-IDR meters.

(3) The Settlement Quality Meter Data submitted by TDSPs must be in kWh and kVarh values (as applicable).

10.3.3.3.1 Past Due Data Submission

ERCOT shall provide a report to the appropriate TDSP for any ESI ID or RID for which consumption data has not been received in the past thirty-eight (38) days. Upon receipt of the missing consumption data report, the TDSP shall have two (2) Business Days to submit the missing consumption data.

10.4 Certification of ERCOT Polled Settlement Metering Facilities

Each TDSP shall certify EPS Metering Facilities in a manner approved by ERCOT.

10.4.1 Overview

This Section describes the steps that TDSPs 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 ERCOT Polled Settlement Design Proposal Documentation Required From the TDSP

Before installation of new EPS Meters, the TDSP 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 MIS. 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 TDSP upon ERCOT's request.

10.4.2.1 Approval or Rejection of an ERCOT Polled Settlement Design Proposal for ERCOT Polled Settlement Metering Facilities

ERCOT may unconditionally approve, conditionally approve, or reject an EPS Design Proposal.

10.4.2.1.1 Unconditional Approval

If ERCOT unconditionally approves an EPS Design Proposal, then ERCOT shall promptly notify the TDSP that the EPS Design Proposal has been approved. The TDSP 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 TDSP 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 TDSP.

(2) Ability to Satisfy Conditions:

If the TDSP disputes any condition imposed by ERCOT, the TDSP must promptly notify ERCOT of its concerns and provide ERCOT with the reasons for its concerns. If the TDSP provides ERCOT such Notice, ERCOT may amend or withdraw any of the conditions on which it granted its approval or ERCOT may require the TDSP to satisfy other conditions. ERCOT and the TDSP shall use good faith efforts to reach agreement on accomplishing the installation.

(3) Notification of Satisfaction of Conditions:

The TDSP 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 TDSP 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 TDSP 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 TDSP 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

If ERCOT rejects an EPS Design Proposal, then ERCOT shall promptly notify the TDSP that the EPS Design Proposal has been rejected and shall set forth the reasons for its rejection. The TDSP 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 TDSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TDSP 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 TDSP ERCOT Polled Settlement Meter Inspector

A TDSP 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.

The TDSP 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 TDSP EPS Meter Inspector.

The TDSP shall provide the documents as outlined in SMOG for each set of EPS Metering Facilities being considered for ERCOT approval.

10.4.3.1 Review by ERCOT

ERCOT shall review the ERCOT site certification documentation prepared by the TDSP EPS Meter Inspector within forty-five (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 TDSP.

ERCOT shall notify the TDSP of the approval of the Metering Facility. ERCOT shall return the original schematic drawings, and the original ERCOT site certification form stamped by ERCOT as approved. ERCOT shall retain a copy of the documents.

10.4.3.2 Provisional Approval

If ERCOT finds that the documentation: provided by the TDSP is incomplete or demonstrates that the EPS Metering Facility fails to meet the standards contained within this Section and the 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 TDSP. 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 MIS on a quarterly basis.

10.4.3.3 Obligation to Maintain Approval

Once an EPS Metering Facility has been installed, it is the responsibility of the TDSP 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

ERCOT may revoke in full or in part any approval of Metering Facilities, including a provisional approval if:

(1) ERCOT or a TDSP 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

(2) ERCOT has given written Notice to the TDSP stating that the identified EPS Metering Facilities do not meet the approval criteria and the reasons and that the TDSP fails to correct the deficiency and satisfy ERCOT, within thirty (30) days, that the EPS Metering Facilities meet the approval criteria.

If ERCOT revokes in full or part an approval of EPS Metering Facilities, the TDSP may seek re-approval of the EPS Metering Facilities by requesting approval in accordance with this Section.

10.4.3.5 Changes to Approved ERCOT Polled Settlement Metering Facilities

Each TDSP 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 (10) Business Days prior to the intended implementation of the change. Before the intended date of the change, ERCOT may request additional information from the TDSP to demonstrate that the EPS Metering Facilities will still meet the applicable approval standards; the TDSP shall promptly comply with such request for information. ERCOT may at its discretion audit Metering Facilities to determine compliance. The TDSP 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

On the written request of ERCOT, the TDSP shall provide ERCOT written or electronic confirmation that the Metering Facilities of each metered Entity that the TDSP represents have been certified in accordance with this Section and the SMOG within five (5) Business Days of receiving such a request from ERCOT.

10.5 TDSP ERCOT Polled Settlement Meter Inspectors

10.5.1 List of TDSP ERCOT Polled Settlement Meter Inspectors

ERCOT shall maintain a list of TDSP EPS Meter Inspectors, and details related to ERCOT training to become a TDSP EPS Meter Inspector.

10.5.2 ERCOT Polled Settlement Meter Inspector Approval Process

10.5.2.1 TDSP Responsibilities

Each TDSP shall ensure that personnel performing EPS Meter Facility certification duties are approved EPS Meter Inspectors and comply with this Section and the SMOG. A TDSP EPS Meter Inspector is required to complete an ERCOT EPS Meter Inspector training session.

The TDSP shall submit to ERCOT the following information for individuals performing EPS Metering Facility certification:

(1) Name of individual;

(2) Time period the individual has been testing Generation Resource or transmission interconnect metering points;

(3) TDSP statement indicating that the individual has the technical expertise to perform EPS Metering Facility certification; and

(4) Additional documentation as required by ERCOT.

10.5.2.2 ERCOT Responsibilities

ERCOT shall hold EPS Meter Inspector training sessions on a regularly scheduled basis. Sessions must include information on the following:

(1) Market responsibilities of EPS Meter Inspectors;

(2) Documentation requirements for the site certification;

(3) Overview of EPS Metering Facilities related topics and documents;

(4) Protocols requirements;

(5) SMOG requirements; and

(6) Technical requirements.

ERCOT shall issue a certificate of attendance to individuals upon completion of the EPS Meter Inspector training sessions.

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 ERCOT Polled Settlement Meter Entities

10.6.1.1 ERCOT Requirement for Audits and Tests

ERCOT shall have the right to audit any EPS Metering Facility that it considers necessary or to request and witness a test carried out by a TDSP EPS Meter Inspector.

10.6.1.2 TDSP Testing Requirements for ERCOT Polled Settlement Metering Facilities

At a minimum, the TDSP 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 TDSP tariffs, the SMOG and these Protocols.

Instrument transformers used in settlement metering circuits must be tested using the following guidelines:

(1) Magnetic Instrument Transformers do not require periodic testing as they have shown themselves to be stable per ANSI C12.1.;

(2) Coupling Capacitor Voltage Transformers (CCVTs) shall, at a minimum, be tested for accuracy on a five (5) year cycle, by the end of the fifth year after the previous test; and

(3) Fiber-optic Current Transformers (CTs) shall, at a minimum, be ratio tested on a five (5) year cycle, by the end of the fifth year after the previous test.

ERCOT may determine that periodic testing of CCVTs and fiber-optic CTs 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

If an EPS Metering Facility fails to comply with ERCOT's audit or test procedures, ERCOT shall issue a warning to the TDSP responsible for such Metering Facilities. If the TDSP fails to comply with ERCOT's recommendations in a reasonable time, as determined by ERCOT, ERCOT shall notify the PUCT or the appropriate Governmental Authority.

10.6.1.4 Requests by Market Participants

Market Participants shall follow appropriate Governmental Authority rules for requesting the testing of Metering Facilities.

10.6.2 TDSP Metered Entities

10.6.2.1 Requirement for Audit and Testing

(1) Audit and Testing by TDSP

Each TDSP shall conduct (or engage a qualified Entity to conduct) audits and tests of the Metering Facilities of the TDSP Metered Entities that it represents to ensure compliance with all applicable requirements of any relevant Governmental Authority. Each TDSP 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 TDSP or its authorized representative.

10.6.2.2 TDSP Requirement to Certify per Governmental Authorities

If a Governmental Authority has authority to certify meter installations, then the TDSPs shall comply with such regulations.

10.7 ERCOT Request for Installation of ERCOT Polled Settlement Metering Facilities

10.7.1 Additional ERCOT Polled Settlement Metering Installations

If ERCOT determines that there is a potential need to install additional EPS Metering Facilities on the ERCOT System, ERCOT shall notify the relevant TDSP in writing or electronically. ERCOT's Notice must include the following information:

(1) The location of the meter point at which the additional EPS Metering Facilities are required;

(2) The projected installation date by which the relevant EPS Metering Facilities should be installed;

(3) The reason for the need to install the additional EPS Metering Facilities; and

(4) Any other information that ERCOT considers relevant.

A TDSP that is notified by ERCOT of the potential need to install additional EPS Metering Facilities must:

(1) Give ERCOT written confirmation of receipt of Notice within three (3) Business Days of receiving such Notice;

(2) Submit an EPS Design Proposal to ERCOT within forty-five (45) Business Days of receiving such Notice.

The TDSP may request a waiver to install additional Metering Facilities.

10.7.2 Approval or Rejection of Waiver Request for Installation of EPS Metering Facilities

ERCOT may approve or reject a waiver request at ERCOT's sole discretion.

10.7.2.1 Approval

If ERCOT approves a waiver request, then ERCOT shall promptly notify the TDSP.

10.7.2.2 Rejection

If ERCOT rejects a waiver request, then ERCOT shall promptly notify the TDSP and shall set forth the reasons for its rejection. The TDSP may submit to ERCOT a revised waiver request within fourteen (14) Business Days of receiving such Notice. If ERCOT rejects, for a second time, a waiver request submitted by a TDSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TDSP 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 Procedures.

10.8 Maintenance of Metering Facilities

10.8.1 ERCOT Polled Settlement Meters

10.8.1.1 Duty to Maintain ERCOT Polled Settlement Metering Facilities

Each TDSP shall maintain its EPS Metering Facilities to meet the standards prescribed by this Section and the SMOG. If the EPS Metering Facilities of a TDSP require maintenance to ensure that they operate in accordance with the requirements of this Section, the SMOG, or any Governmental Authority, then the TDSP shall notify ERCOT of the need for such maintenance. The TDSP shall also inform ERCOT five (5) Business Days in advance of the time period during which such maintenance is expected to occur. During that period, the TDSP, 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 ERCOT Polled Settlement Metering Facilities Repairs

If an EPS Metering Facility requires repairs to ensure that it operates in accordance with the requirements of this Section, then the TDSP shall immediately notify ERCOT of the need for repairing such Facility. If, however, operating conditions are such that it is not possible for the 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.

(1) Where no Back-up Meter exists or back-up meter data is unavailable, the TDSP shall ensure that the metering point is repaired and operational within twelve (12) hours of problem detection;

(2) Where a functional and operational Back-up Meter exists, the TDSP shall ensure that the metering point is repaired and operational within five (5) Business Days of problem detection.

10.8.2 TDSP Metered Entities

Each TDSP 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

For settlement purposes, IDR meters are required on any of the following locations/sites:

(1) Generation Resources (with the exception of those excluded in this Section);

(2) Resources bidding into the Ancillary Services Market;

(3) NOIE metering points used to determine NOIE total Load;

(4) Service Delivery Points connected to the transmission system (>60KV); and

(5) Locations meeting IDR Requirements defined in Section 18, Load Profiling.

10.9.1 ERCOT-Polled Settlement Meters

The TDSP for EPS meters shall ensure that the EPS Metering Facilities comply with this Section and the SMOG.

IDR meters used for settlement of EPS Metering Facilities shall:

(1) Capture energy consumption and/or production in increments consistent with ERCOT defined Settlement Interval;

(2) Be able to capture energy in increments of five (5) minutes (excluding memory allocation) for new and replacement IDR meters used for settlement;

(3) Provide interval data for daily polling on a schedule that supports ERCOT's requirements (typically a daily cycle);

(4) Be capable of having data retrieved via telemetry by MDAS;

(5) Have battery or other energy-storage back-up to maintain time during power outages;

(6) Have remote time synchronization capability compatible with the MDAS;

(7) Maintain meter clocks on a time reference standard that enables ERCOT MDAS to maintain the IDR data on the Central Prevailing Time. The meter clock shall be synchronized to within +/- one percent (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

(8) Divide each hour into Settlement Intervals ending as follows:

XX:15:00
XX:30:00
XX:45:00
XX:00:00

10.9.2 TDSP Metered Entities

IDR meters used for settlement of TDSP Metered Entities shall:

(1) Capture energy consumption in increments consistent with, or in fractions of, ERCOT-defined settlement time interval;

(2) Provide interval data on a schedule that supports the requirements of final settlement;

(3) Have battery or other energy-storage back-up to maintain time during power outages;

(4) Have time synchronization capability;

(5) Maintain meter clocks on a time reference that enables the TDSP to submit data on the Central Prevailing Time. The meter clock shall be synchronized to within at least +/- five percent (5%) of the Settlement Interval when compared to the National Institute of Standards and Technology (NIST) Atomic Clock;

(6) Have data aggregated to the appropriate Settlement Interval time block by the TDSP prior to the data being sent to ERCOT if recorded at increments less than the ERCOT defined settlement interval;

(7) Be able to capture energy in increments of five (5) minutes (excluding memory allocation) for new and replacement IDR meters used for settlement;

(8) Divide each hour into Settlement Intervals ending as follows:

XX:15:00
XX:30:00
XX:45:00
XX:00:00

(9) 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

If the TDSP fails to comply with the standards for EPS Metering Facilities referred to in this Section and the SMOG, then ERCOT shall notify the PUCT or the appropriate Governmental Authority.

10.10 Security of Meter Data

10.10.1 ERCOT Polled Settlement Meters

TDSP's are responsible for data security of the EPS Metering Facilities on their system. This responsibility extends to third-party contracts and access to EPS Metering Facilities.

TDSPs or any Entity authorized to poll EPS Meters may not issue any EPS Meter programming passwords to any Market Participant.

10.10.1.1 TDSP Data Security Responsibilities

The TDSP shall:

(1) Maintain and modify the passwords for programming and read access to EPS Meters;

(2) Provide the appropriate password access to ERCOT, which will allow ERCOT to synchronize the meter clock;

(3) Establish any other security requirements for accessing the EPS Meters so as to ensure the security of those meters and their meter data;

(4) 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;

(5) 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 QSE Load, to the extent that such provision does not violate the customer service and protection provisions of the PUCT Substantive Rules; and

(6) 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

ERCOT may request that the TDSP alter the password and other requirements for accessing EPS Meters, as it deems necessary.

10.10.1.3 Resource Entity Data Security Responsibilities

A Resource Entity must request that the TDSP 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

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

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.

ERCOT shall provide TDSPs with uniquely numbered seals to be used by the TDSP 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 TDSP Metered Entities

Security for TDSP polled meters and meter data shall be the responsibility of the TDSP. Each TDSP shall maintain polled meters in accordance with applicable Governmental Authority rules and regulations. The TDSP 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 ERCOT Polled Settlement Meters

The raw meter data that ERCOT retrieves from EPS Meters must be processed by MDAS using the Validating, Editing, and Estimating (VEE) procedures published in Section 11, Data Acquisition and Aggregation, and the 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

At the request of ERCOT, TDSPs and Market Participants 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 TDSP Settlement Meters

The TDSP shall provide ERCOT with Settlement Quality Meter Data for the TDSP Settlement Meters on its system and shall ensure that at a minimum the VEE requirements as specified in the Uniform Business Practices (UBP) standard for Validating, Editing, and Estimating have been properly performed on such data. ERCOT shall not perform any VEE on the Settlement Quality Meter Data it receives from TDSPs.

The following UBP manual validation processes are exempt for Interval Data:

(1) Spike Check; and

(2) Reactive channel check for kWh data

10.12 Communications

10.12.1 ERCOT Acquisition of Meter Data

ERCOT shall acquire meter data via the following communication links:

(1) ERCOT private communication network established by ERCOT for ERCOT Real Time metered Entities; and

(2) Standard voice telephone circuit or other ERCOT-approved communication technology provided by the TDSP for ERCOT Polled Settlement (EPS) Meters.

10.12.2 TDSPs Meter Data Submittal to ERCOT

Transmission and/or Distribution Service Providers (TDSPs) 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, TDSPs shall use an automated system with an ERCOT approved and tested interface to MDAS.

10.12.3 ERCOT Distribution of Settlement Quality Meter Data

ERCOT shall distribute Settlement Quality Meter Data to Market Participants via:

(1) Market Information System (MIS) Pass-Through – When a TDSP submits meter consumption data to ERCOT via a Texas Standard Electronic Transaction (TX SET), information pertaining to specific Market Participants shall be removed and automatically forwarded on to that specific Market Participant (i.e., a Competitive Retailer (CR) will automatically receive the meter consumption data and other information for the ESI IDs that the CR represented during the meter data timeframe).

(2) On Request – A Market Participant may submit an electronic request via the MIS for specific meter consumption data. ERCOT will receive and validate the request and, if appropriate, automatically forward the appropriate information to the Market Participant.

[PRR766: Replace Section 10.12.3 above with the following upon system implementation:]

ERCOT shall distribute Settlement Quality Meter Data to Market Participants via:

(1) Market Information System (MIS) Pass-Through – When a TDSP submits meter consumption data to ERCOT via a Texas Standard Electronic Transaction (TX SET), information pertaining to specific Market Participants shall be removed and automatically forwarded on to that specific Market Participant (i.e., a Competitive Retailer (CR) will automatically receive the meter consumption data and other information for the ESI IDs that the CR represented during the meter data timeframe).

(2) Whenever a TDSP 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 in a secure manner.

(3) On Request – A Market Participant may submit an electronic request via the MIS 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

The device id used to identify an 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 TDSP if the device id selected has been used elsewhere in MDAS.

10.14 Exemptions from Compliance to Metering Protocols

10.14.1 Authority to Grant Exemptions

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). Any permanent exemption shall be subject to periodic review and revocation by TAC.

10.14.2 Guidelines for Granting Temporary Exemptions

ERCOT shall use the following process when considering applications for temporary exemptions from compliance with this Section and the SMOG.

(1) Publication of Guidelines: ERCOT shall post on the MIS the general guidelines that it will use when considering applications for exemptions within one (1) week 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.

(2) Publication of Decision: ERCOT shall post on the MIS 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

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 (3) Business Days of receipt. For temporary exemptions, ERCOT shall decide whether to grant or reject the exemption within forty-five (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.

The applicant shall provide such additional information to ERCOT within five (5) Business Days of receiving the request or within such other period as ERCOT may specify. If ERCOT requests additional information more than forty (40) Business Days after the date on which it received the application, ERCOT shall have an additional seven (7) 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

The application for exemption to ERCOT shall include:

(1) 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;

(2) A detailed statement of the reason for seeking the exemption, including any supporting documentation;

(3) Details of the Entity(s) to which the exemption will apply;

(4) Details of the location to which the exemption will apply;

(5) Details of the period of time for which the exemption will apply, including the proposed start and finish dates of that period; and

(6) Any other information requested by ERCOT.

ERCOT Protocols
Section 11: Data Acquisition and Aggregation

January 1, 2009

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11 DATA ACQUISITION AND AGGREGATION

11.1 Data Acquisition And Aggregation From ERCOT Polled Settlement (EPS) Metered Entities

11.1.1 Overview

ERCOT will collect interval data from all ERCOT Polled Settlement (EPS) metered Entities according to Section 10, Metering of these Protocols. 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 EPS Meter Data Collection

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 IDR protocol (TIM 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 TDSP to resolve data collection problems within the time frame defined in Section 10, Metering.

11.1.3 EPS Meter Time Synchronization

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 TDSP regarding any meter that is determined to be inconsistent in its timekeeping function. The TDSP will facilitate correction of this problem within the time frame detailed in Section 10, Metering.

11.1.4 EPS Meter Data Validation, Editing, and Estimation (VEE)

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:

(1) Flagging of intervals with missing data;

(2) Exception reporting if the total number of zero values for any channel exceeds the tolerance limit;

(3) Exception reporting if the total number of power outage intervals exceeds the tolerance limit;

(4) Channel level exception reporting if any single interval breaches the upper or lower threshold of the limit;

(5) Channel level validation of the percent change between two consecutive intervals being greater than the established tolerance limit;

(6) Data overlap validation test, which rejects validations when the current interrogation of data overlaps data previously collected;

(7) 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;

(8) Validation that the number of expected intervals equals the number of actual intervals collected during the interrogation process; and

(9) Validation of data between primary, backup and check meters where available.

ERCOT will perform editing and estimation of EPS meter data according to the Protocols defined in Section 10, Metering. The Validation process occurs each time data is collected from a meter.

11.1.5 Loss Compensation of EPS Meter Data

Adjustments will be made to actual metered consumption to accommodate the energy consumption related to line and transformation losses to the point of interconnection with the ERCOT Transmission Grid. These adjustments are intended specifically to correct the metered consumption when the meter is not located at the point of interconnection with the ERCOT Transmission Grid.

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 MDAS will have the ability to perform approved loss compensation as necessary.

TDSPs requesting loss compensation for a specific meter will comply with Section 10 of these Protocols and the Operating Guides. ERCOT will provide a compensation mechanism based upon a single percentage value submitted by the TDSP 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 TDSP submits, and ERCOT approves, revised loss compensation values. The loss compensation percentage values should not be changed more than once annually.

11.1.6 EPS Meter Netting

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

11.1.7 EPS Generation Meter Splitting

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 EPS Meter Data for Non Opt-In Transmission Losses

ERCOT will correct the total Load of EPS meters for Non Opt-In Entities 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 of these Protocols, ERCOT will populate Settlement Interval Load data for Non Opt-In Entities into a single data set to be used in the Load aggregation process Non Opt-In Entities will be able to extract Load data from the Data Archive via the MIS.

11.1.9 Treatment of Non Opt-In Radially Connected Entities

At Non Opt-In metering points for which the TDSP is supplying data to ERCOT, the interval Load data that is not bi-directional will have each point of delivery treated as an individual ESI ID.

11.1.10 Treatment of EPS Load Data

For EPS metering that ERCOT is populating ESI ID Load data, ERCOT will:

(1) Utilize the data for all settlement calculations and reports;

(2) Provide the TDSP and LSE with daily KWH consumption information in accordance with SET 867_03 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 SET 867_03 being provided to the TDSP and LSE;

(3) Accommodate retail switching via the standard switching process and timelines;

(4) Be identified as the Meter Reading Entity (MRE); and

(5) Make ESI ID interval data available to the TDSP and LSE via an extract.

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 EPS RIDs Data

For EPS RID data, ERCOT will:

(1) Be identified as the MRE; and

(2) Model and populate data to appropriate channels such that netting and aggregation conform to the ERCOT Protocols requirements.

(3) Make RID interval and SCADA interval data available to the associated QSE, TDSP, Resource Entity, and LSE via an extract.

The ERCOT RIDs 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 TDSPs no later than noon on the tenth (10th) Business Day after ERCOT reads the EPS meter; and

(d) Whenever ERCOT makes an edit to data previously provided to the TDSP, ERCOT shall provide the revised data to the TDSP by noon of the tenth (10th) Business Day after the edit is made.

11.2 Data Acquisition From TDSPs

11.2.1 Overview

This section addresses the manner in which ERCOT will receive and validate data from the Transmission and/or Distribution Service Providers (TDSPs) regarding usage for Generation Resources and Load from TDSPs' metered Entities as defined in Section 10, Metering.

11.2.2 Data provision and verification of Non EPS Metered Points

The TDSP will provide data for TDSP Metered Entities as defined in Section 10, Metering.

The TDSP will provide data in accordance with the TDSP meter data responsibilities detailed in Section 10 and will conform to data formats specified in Section 19, Texas Standard Electronic Transaction.

ERCOT will:

(1) Provide the TDSP a notification of successful/unsuccessful data transfer for the meter data submitted. At the Electric Service Identifier (ESI ID) level, the TDSP will be notified of successful and unsuccessful validations;

(2) Validate that the correct TDSP is submitting meter consumption data on an individual ESI ID basis. At the ESI ID level, the TDSP will be notified of unsuccessful validations;

(3) Provide a report to the TDSP listing each ESI ID for which ERCOT has not received consumption data for thirty-eight (38) days; and

(4) Synchronize the Meter Data Acquisition System (MDAS) 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 Power Generation Entity, and the meter. MDAS will provide versioning to ensure ESI ID characteristic changes are time stamped.

11.3 ESI ID Synchronization

11.3.1 ESI ID Service History and Usage

On a daily basis, ERCOT shall provide incremental updates to ESI ID service history and usage information to LSEs, MREs, and TDSPs. ESI ID service history includes ESI ID relationships and ESI ID characteristics.

11.3.2 Variance Process

Any LSE, MRE, or TDSP 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

A LSE, MRE, or TDSP 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

Data Aggregation is the process of netting, grouping and summing Load consumption data, applying appropriate profiles, Transmission Loss Factors and Distribution Loss Factors and calculating and allocating UFE to determine each QSE and/or Load Serving Entities responsibility by Settlement Interval by Congestion Zone 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

The Data Aggregation System 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

The Data Aggregation System will distinguish each 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:

(1) QSE;

(2) Load Serving Entity;

(3) Congestion Zone;

(4) UFE zone;

(5) Profile ID;

(6) Distribution Loss Factor code;

(7) TDSP;

(8) Read start date (reading from date); and

(9) Read stop date (reading to date).

Estimates of missing data are based on Profile ID, which includes:

(1) Profile Type;

(2) Weather Zone;

(3) Meter type;

(4) Weather sensitivity; and

(5) TOU Schedule.

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.

$$\mathbf{PND_{Operating\ Day}} = (\Sigma \mathbf{Actual\ KWH_{Specific\ Time\ Period}} / \Sigma \mathbf{CP\ KWH_{Specific\ Time\ Period}}) * \mathbf{LP_{Operating\ Day}}$$

Where:

PND	Profiled Non-Interval Data
CP	Class Profile
LP	Load Profile (daily interval data set) in KWh

Any active ESI ID on the Operating Day being settled for which ERCOT does not have a meter read within twelve (12) months of the Operating Day will not have a usage estimate applied to their 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

ERCOT will estimate all ESI IDs with IDRs for which consumption data has not been received for the Operating Day. The method for estimating interval data for ESI IDs with IDRs is a "Weather Response Informed Proxy Day" technique. This approach seeks to increase estimation accuracy by segmenting ESI IDs with IDRs into two groups based on a known indicator of Load, i.e. weather. The classification of ESI IDs 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.

11.4.3.1 Weather Responsiveness Determination

ERCOT shall perform the weather responsiveness test for all ESI IDs with IDRs as specified below.

For each ESI ID with an IDR, 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 summer (June 1st – September 30th) immediately preceding the date the test is run:

(1) Daily kWh; and,

(2) Average Weather Zone daily dry bulb temperature

$$= \quad ((MAX + MIN)/2)$$

Where:

MAX	=	maximum Weather Zone daily dry bulb temperature
MIN	=	minimum Weather Zone daily dry bulb temperature

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.

The weather responsiveness determination shall be performed annually between November 1st and November 15th.

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 MIS by November 20th.

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 fifty percent (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.

If, for a specific ESI ID, fifty percent (50%) or more of the data required for the calculations described above is missing, the ESI ID shall retain its current weather sensitivity classification.

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 summer 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.

TDSPs shall successfully complete Weather Sensitivity Code modifications (Profile ID changes) no later than sixty (60) days after the ESI ID appears on the ERCOT report. Profile ID changes shall be effective as of the most current meter read date.

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.

As a part of the Profile Class assignment, TDSPs will assign a Non-Weather Sensitive classification to all newly installed IDRs. TDSP shall also assign a default Profile Type to all IDRs to serve as a final default estimation routine provided all proxy day selection criteria are exhausted. Use of the default Profile Type is defined further in Section 11.4.3.2, Weather Sensitive (WSIDR) Proxy Day Method, and Section 11.4.3.3, Non-Weather Sensitive (NWSIDR) Proxy Day Method.

11.4.3.2 Weather Sensitive (WSIDR) Proxy Day Method

For ESI IDs designated as 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:

(1) To determine eligible proxy days, select all days (of matching weekday/weekend day type and season) 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 (2) 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.

(2) Perform two (2) tests on each potential proxy day identified in Step 1;

(a) 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.

(b) 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.

(3) Each potential proxy day for each test described in Step 2 is ranked in ascending order based on the sum of squared differences.

(4) A final ranking is performed with the temperature magnitude test weighted more heavily than the shape test. The weighting factors are seventy percent (70%) and thirty percent (30%).

(5) Select the top three ranked eligible days.

(6) For each ESI ID, do the following:

(a) Use the top ranked proxy day for the target Operating Day, if available.

(b) If the top ranked proxy day data is not available, use the second ranked proxy day data as the estimate.

(c) If the second ranked proxy day data is not available, use the third proxy day.

(d) If no data is available for any of the proxy days selected, then default to the non-weather sensitive proxy day selection list.

(e) 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 (NWSIDR) Proxy Day Method

For ESI IDs designated as NWSIDR, ERCOT will use a method for proxy day determination. This method incorporates the following:

(1) 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 (Su, M, T, W, Th, F, Sa) corresponding to the day of the week of the Operating Day (Holidays are treated as Sundays) within the most recent twelve (12) months of the Operating Day; or

(2) If there is no historic interval data available according to (1) 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 twelve (12) months of the Operating Day is available, and if the ESI ID was profiled with a non-interval meter data type code within ninety (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 IDR Estimation Reporting

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

The Data Aggregation System 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

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:

(1) QSE

(2) Load Serving Entity

(3) Congestion Zone

(4) UFE zone

(5) Profile ID

(6) Distribution Loss Factor code

(7) TDSP

(8) Read start date (reading from date)

(9) Read stop date (reading to date)

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.

$$\mathbf{PND}_{\text{Operating Day}} = (\Sigma\mathbf{Actual\ KWH}_{\text{Specific Time Period}} / \Sigma\mathbf{CP\ KWH}_{\text{Specific Time Period}}) * \mathbf{LP}_{\text{Operating Day}}$$

Where:

PND	Profiled Non-Interval Data
CP	Class Profile
LP	Load Profile (daily interval data set) in KWh

11.4.4.2 Load Reduction for Excess PhotoVoltaic Renewable Generation

Adjusted Metered Load (AML) for ESI IDs with PhotoVoltaic (PV) generation shall be adjusted as follows:

(1) AML shall be reduced for excess generation from ESI IDs with PV generation of less than fifty (50) kW 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.

(2) Intervals beginning 11:00 A.M. and ending 3:00 P.M. CPT (spanning sixteen (16) 15-minute intervals) shall be reduced by the following amount:

$$\mathbf{PV\_adjust_i = kWh\_Gen / (read\_days * 16)}$$

Where:

PV_adjust_i	Reduction for PV excess generation for interval i
kWh_Gen	Actual (measured) kWh flowing into the Distribution System (outflow from the Premise)
read_days	Number of days in meter read period

[PRR756: Replace Section 11.4.4.2 above with the following upon system implementation.]

11.4.4.2 Load Reduction for Excess PhotoVoltaic Renewable Generation

Adjusted Metered Load for ESI IDs with PhotoVoltaic (PV) generation shall be adjusted as follows:

(1) Prior to the application of item (2) of this Section, Adjusted Metered Load shall be reduced for excess generation from ESI IDs with PhotoVoltaic (PV) generation of less than fifty (50) kW 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 11:00 A.M. and ending 3:00 P.M. CPT (spanning sixteen (16) 15-minute intervals) shall be reduced by the following amount:

$$\mathbf{PV\_adjust_i = kWh\_Gen / (read\_days * 16)}$$

Where:

PV_adjust_i	Reduction for PV excess generation for interval i
kWh_Gen	Actual (measured) kWh flowing into the Distribution System (outflow from the Premise)
read_days	Number of days in meter read period

(2) The PV reduction adjustment for ESI IDs, which have PV generation of less than 50 kW behind the meter and that have an Advanced Metering System (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.

11.4.4.3 Load Reduction for Excess Non-PhotoVoltaic Renewable Generation

AML for ESI IDs with non-PV renewable generation shall be adjusted as follows:

(1) AML shall be reduced for excess generation from ESI IDs with non-PV renewable generation of less than fifty (50) kW 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 non-PV renewable Distributed Renewable Generation

profile segment as specified in Load Profiling Guide Appendix D, Profile Decision Tree, shall be eligible for this reduction.

(2) All intervals in the meter read period shall be reduced by the following amount:

$$\textbf{REn\_adjust}_{\mathbf{i}} = \textbf{kWh\_gen / read\_ints}$$

Where:

REn_adjust_i	Reduction for non-PV excess renewable generation for interval i
kWh_gen	Actual (measured) kWh flowing into the Distribution System (outflow from the Premise)
read_ints	Number of 15-minute intervals in the meter read period

[PRR756: Replace Section 11.4.4.3 above with the following upon system implementation.]

Adjusted Metered Load for ESI IDs with non-PV renewable generation shall be adjusted as follows:

(1) Prior to the application of item (2) of this Section, Adjusted Metered Load shall be reduced for excess generation from ESI IDs with non-PV renewable generation of less than fifty (50) kW 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 non-PV renewable Distributed Renewable Generation 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:

$$\textbf{REn\_adjust}_{\mathbf{i}} = \textbf{kWh\_gen / read\_ints}$$

Where:

REn_adjust_i	Reduction for non-PV excess renewable generation for interval i
kWh_gen	Actual (measured) kWh flowing into the Distribution System (outflow from the Premise)
read_ints	Number of 15-minute intervals in the meter read period

(2) The renewable energy reduction adjustment for ESI IDs, which have renewable generation of less than fifty (50) kW behind the meter and have an Advanced Metering System (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

The ERCOT Data Aggregation System shall adjust consumption data for Transmission and Distribution Losses. The sources of data used in this process are:

(1) Estimated non-interval data profiled via usage factor routine

(2) Estimated proxy day interval data

(3) Profiled actual non-interval data

(4) Actual interval data

(5) Distribution Loss Factors

(6) Transmission Loss Factors (Average ERCOT-Wide)

ERCOT will apply Distribution Loss Factors to aggregate levels of Load data in accordance with Section 13, Transmission and Distribution Losses, of these Protocols. Aggregated Loads will be adjusted for Distribution Losses based upon Distribution Loss Factor code correlated to the Distribution Loss Factor for each TDSP. Loads that are transmission connected or that are settled at transmission level will not be allocated distribution level losses.

$$\mathbf{NDLAL_{i\ Aggregated\ Group} = BL_{i\ Aggregated\ Group} * 1 / (1 - DLF_{i\ Aggregated\ Group})}$$

Where:

i	Interval
$NDLAL_i$	Net distribution loss adjusted Load
BL_i	Base Load
DLF_i	Distribution Loss Factor (voltage code specific)

ERCOT will apply the ERCOT wide Transmission Loss Factor to the net distribution loss adjusted Loads to produce a net loss adjusted aggregated Load value for each aggregation set. ERCOT wide Transmission Loss Factors will be developed in accordance with Section 13, Transmission and Distribution Losses, of these Protocols.

$$\mathbf{NLAL_{i\ Aggregated\ Group} = NDLAL_{i\ Aggregated\ Group} * 1 / (1 - TLF_i)}$$

Where:

i	Interval
$NLAL_i$:	Net loss adjusted Load
$NDLAL_i$:	Net distribution loss adjusted Load
TLF_i:	Transmission Loss Factor (ERCOT wide factor)

11.4.6 Unaccounted for Energy Calculation (UFE) and Allocation

The Data Aggregation System shall adjust the net loss adjusted Load for each aggregated group for Unaccounted for Energy (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 Loads. Net flow out of ERCOT on a DC Tie will be deemed as Load, and net flow into ERCOT on a DC Tie will be deemed as a Resource

11.4.6.1 Calculation of ERCOT-Wide UFE

The Data Aggregation System will calculate ERCOT-wide UFE as the difference between the total generation supplied to a specific physical region (ERCOT) and the total Load, adjusted for losses in that same physical region (ERCOT) during each Settlement Interval. UFE may be positive or negative in any single Settlement Interval.

$$\textbf{UFE}_{\mathbf{i}}\ \textbf{(MWh)} = \textbf{ERCOT Generation}_{\mathbf{i\ Total}} - \textbf{ERCOT Net Loss Adjusted Load}_{\mathbf{i\ Total}}$$

11.4.6.2 Allocation of UFE

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:

(1) 0.0 - Transmission Voltage level IDR Non Opt-in Entities

(2) 0.10 - Distribution Voltage level IDR Non Opt-in Entities

(3) 0.10 - Transmission Voltage level IDR Premises

(4) 0.50 - Distribution Voltage level IDR Premises

(5) 1.00 - Distribution Voltage level Profiled Premises

The ERCOT Data Aggregation System shall provide a mechanism to change the UFE category weighting factors for specific transition periods.

11.4.6.3 UFE Allocation to UFE Categories:

For each premise category, and for each settlement interval, the UFE allocated to each UFE category is calculated as follows:

$$\text{UFE}_{\text{PRiz}} = \text{UFE}_{\text{iz}} \ \text{X} \ [(\text{f}_{\text{PRiz}} \ \text{X} \ \text{L}_{\text{PRiz}}) / \text{L}_{\text{UFEiz}}]$$

$$\text{UFE}_{\text{IDRiz}} = \text{UFE}_{\text{iz}} \ \text{X} \ [(\text{f}_{\text{IDRiz}} \ \text{X} \ \text{L}_{\text{IDRiz}}) / \text{L}_{\text{UFEiz}}]$$

$$UFE_{TRiz} = UFE_{iz} \times [(f_{Triz} \times L_{TRiz}) / L_{UFEiz}]$$

$$UFE_{TNOIEiz} = UFE_{iz} \times [(f_{TNOIEiz} \times L_{TNOIEiz}) / L_{UFEiz}]$$

$$UFE_{DNOIEiz} = UFE_{iz} \times [(f_{DNOIEiz} \times L_{DNOIEiz}) / L_{UFEiz}]$$

$$L_{UFEiz} = f_{PRiz} \times L_{PRiz} + f_{IDRiz} \times L_{IDRiz} + f_{TRiz} \times L_{TRiz} + f_{TNOIEiz} \times L_{TNOIEiz} + f_{DNOIEiz} \times L_{DNOIEiz}$$

$$\mathbf{L_{UFEi} = SUM(L_{UFEiz})_z}$$

Where:

i	Interval
z	Zone
UFE_{PRiz}	Amount of UFE allocated to Profile category
UFE_{IDRiz}	Amount of UFE allocated to IDR category
UFE_{TRiz}	Amount of UFE allocated to Transmission category
$UFE_{TNOIEiz}$	Amount of UFE allocated to Transmission voltage level NOIE category
$UFE_{DNOIEiz}$	Amount of UFE allocated to Distribution voltage level NOIE category
$UFE_{\mathbf{i}}$	Total ERCOT system UFE

and

$L_{PR\mathbf{iz}}$ =	Aggregate Load of Profile category – Adjusted for losses
$L_{IDR\mathbf{iz}}$ =	Aggregate Load of all IDR category – Adjusted for losses
$L_{TR\mathbf{iz}}$ =	Aggregate Load of Transmission category – Adjusted for losses
$L_{TNOIE\mathbf{iz}}$ =	Aggregate Load of Transmission level non opt-in category – Adjusted for losses
$L_{DNOIE\mathbf{iz}}$ =	Aggregate Load of Distribution level non opt-in category – Adjusted for losses

and

$f_{PR\mathbf{iz}}$ =	Adjustment Percentage for Profiled premises per interval per zone
$f_{IDR\mathbf{iz}}$ =	Adjustment Percentage for IDR premises per interval per zone
$f_{TR\mathbf{iz}}$ =	Adjustment Percentage for Transmission premises per interval per zone
$f_{TNOIE\mathbf{iz}}$ =	Adjustment Percentage for Transmission voltage level non opt-in premises per interval per zone
$f_{DNOIE\mathbf{iz}}$ =	Adjustment Percentage for Distribution voltage level non opt-in premises per interval per zone
$L_{UFE\mathbf{iz}:}$ =	Adjusted total UFE Allocation reference Load

11.4.6.4 UFE Allocation to LSEs within UFE Categories

The UFE allocated to each UFE category type is then allocated to the LSEs within each UFE category based upon each LSEs share of the total Load for the UFE category.

$$UFE_{PRiz\ LSE} = UFE_{PRiz} \times (L_{PRiz\ LSE} / L_{PRiz})$$

$$UFE_{IDRiz\ LSE} = UFE_{IDRiz} \times (L_{IDRiz\ LSE} / L_{IDRiz})$$

$$UFE_{TRiz\ LSE} = UFE_{TRiz} \times (L_{TRiz\ LSE} / L_{TRiz})$$

$$UFE_{TNOIEiz\ LSE} = UFE_{TNOIEiz} \times (L_{TNOIEiz\ LSE} / L_{TNOIEiz})$$

$$UFE_{DNOIEiz\ LSE} = UFE_{DNOIEiz} \times (L_{DNOIEiz\ LSE} / L_{DNOIEiz})$$

Where:

i	Interval
z	Zone
$UFE_{PRiz\ LSE}$	UFE allocated to LSE in UFE profile category
$UFE_{IDRiz\ LSE}$	UFE allocated to LSE in UFE IDR category
$UFE_{TRiz\ LSE}$	UFE allocated to LSE in UFE Transmission category
$UFE_{TNOIEiz\ LSE}$	UFE allocated to LSE in UFE Transmission NOIE category
$UFE_{DNOIEiz\ LSE}$	UFE allocated to LSE in UFE Distribution NOIE category

and

UFE_{PRiz}	Amount of UFE allocated to Profile category
UFE_{IDRiz}	Amount of UFE allocated to IDR category
UFE_{TRiz}	Amount of UFE allocated to Transmission category
$UFE_{TNOIEiz}$	Amount of UFE allocated to Transmission voltage level NOIE category
$UFE_{DNOIEiz}$	Amount of UFE allocated to Distribution voltage level NOIE category

and

$L_{PRiz\ LSE}$	LSE Load in Profile Category – Adjusted for losses
$L_{IDRiz\ LSE}$	LSE Load in IDR Category – Adjusted for losses
$L_{TRiz\ LSE}$	LSE Load in Transmission Category – Adjusted for losses
$L_{TNOIEiz\ LSE}$	LSE Load in Transmission NOIE Category – Adjusted for losses
$L_{DNOIEiz\ LSE}$	LSE Load in Distribution NOIE Category – Adjusted for losses

and

L_{PRiz}	Aggregate Load of Profile category – Adjusted for losses
L_{IDRiz}	Aggregate Load of all IDR category – Adjusted for losses
L_{TRiz}	Aggregate Load of Transmission category – Adjusted for losses
$L_{TNOIEiz}$	Aggregate Load of Transmission level non opt-in category – Adjusted for losses
$L_{DNOIEiz}$	Aggregate Load of Distribution level non opt-in category – Adjusted for losses

11.5 Data Aggregation

11.5.1 Aggregate Retail Load Data

Adjusted Metered Load (AML), defined as retail Load data that has been adjusted for UFE and Transmission and/or Distribution Losses, will be aggregated into distinct grouping and segments such as LSE, QSE, and Congestion Zone, and provided to settlement.

11.5.1.1 Aggregated Load Data Posting/Availability

ERCOT will make available to Market Participants the following information on a daily basis:

(1) LSE Load Ratio Share data by ERCOT total.

(2) LSE base Load values, by unique combination of QSE, Congestion Zone, UFE zone, Profile Type, Distribution Loss Factor code and TDSP.

(3) LSE base Load plus allocation of Distribution Losses by unique combination of QSE, Congestion Zone, UFE zone, Profile Type, Distribution Loss Factor code and TDSP.

(4) LSE base Load plus allocation of Distribution Losses and Transmission Losses by unique combination of QSE, Congestion Zone, UFE zone, Profile Type, Distribution Loss Factor code and TDSP.

(5) LSE base Load plus allocation of Distribution Losses, Transmission Losses UFE; by unique combination of QSE, Congestion Zone, UFE zone, Profile Type, Distribution Loss Factor code and TDSP allocation of Distribution Losses, Transmission Losses and UFE.

[PRR577: Insert item (6) upon system implementation.]

(6) TDSP base Load plus allocation of Distribution Losses, Transmission Losses, and UFE; by TDSP.

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 MIS within forty-eight (48) hours of finalizing the data for Settlement Statements.

11.5.2 Generation Meter Data Aggregation

ERCOT will perform generation aggregation by the following distinct criteria sets:

(1) By UFE zone: This data set is used in the calculation of Unaccounted for Energy (UFE) in the Load aggregation process.

(2) By Generation Resource (meter ID), by Generation Entities, by QSE and Congestion Zone: This data set is passed to the settlement process for generation imbalance calculations.

11.5.2.1 Participant Specific Generation Data Posting/Availability

The following market-specific generation information will be made available by ERCOT to each Market Participant:

(1) Generation Unit Production by Generation Resource Entity

(2) Generation Resource Entity total generation production by Congestion Zone

(3) QSE total generation production by Congestion Zone

Each Market Participant will have access only to its own information and/or the information of the Entities, which it represents.

11.5.2.2 General Public Generation Data Posting/Availability

The following general market generation information will be posted to the MIS:

(1) Total Generation

(2) Total AML

ERCOT will make the aforementioned data for each settlement run type available to Market Participants via MIS within forty-eight (48) hours of finalizing the data for Settlement Statements.

11.6 Unaccounted For Energy (UFE) Analysis

11.6.1 Overview

ERCOT will provide an annual 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 Market Information System (MIS) by April 30th. The appropriate TAC Subcommittee may:

(1) Request interim UFE analysis reports;

(2) 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:

(a) Cost-benefit analysis;

(b) Installation requirements for Revenue Quality Meters;

(c) Impact on the settlement system;

(d) Impact on Market Participant systems;

(e) Cost of UFE to Market Participants;

(3) Identify factors that are contributing to UFE and work with the appropriate Entities to rectify problems causing UFE;

ERCOT currently has one (1) UFE zone for settlement purposes, which encompasses all of ERCOT.

11.6.2 Annual UFE Analysis Report

The annual UFE analysis report will contain both ERCOT-wide and UFE allocation category quantities as follows:

(1) Total UFE MWhs;

(2) Total UFE cost;

(3) Percent of total UFE to ERCOT Load;

(4) Percent of total UFE cost; and

(5) Notice of any factors that may be contributing to UFE

ERCOT Protocols
Section 12: Market Information System

February 1, 2009

12 MARKET INFORMATION SYSTEM

12.1 Overview

ERCOT shall create and maintain an electronic market information system ("ERCOT Market Information System" or "MIS"). The MIS shall contain real-time access to information concerning the transfer capability of the ERCOT Transmission Grid and the market clearing prices of Ancillary Services. ERCOT shall ensure that all Market Participants have access to the ERCOT MIS on a nondiscriminatory basis.

The ERCOT OASIS will, at a minimum, provide all information required under any regulations of Public Utility Commission of Texas (PUCT) or other Governmental Authorities. The MIS shall also include any available non-Protected Information that is useful to QSEs for the purposes of estimating or verifying bills for all ERCOT-provided settlements.

Upon request by the Eligible Transmission Service Customer, ERCOT shall provide the methodology and data to independently reproduce information related to the total transfer capability between Congestion Zones and to, from, and over the DC Ties contained in the MIS.

12.2 ERCOT Obligation to Provide Information

The Market Information System (MIS) shall accommodate the posting of information as directed throughout these Protocols. This information shall include:

(1) Transmission-related information, including full interconnection requests as described in Section 1.3.1.2, Items Not Considered Protected Information;

(2) Market-related information;

(3) Current and forecasted system conditions of relevance to the commercial operations of Market Participants;

(4) System conditions related to reliability; and

(5) Other ERCOT System related information.

The MIS is not to be used as a marketplace for transmission rights or other products or services. The ERCOT MIS shall include security measures to protect the confidentiality of Market Participants' Protected Information.

ERCOT shall promptly post information, other than Protected Information, that it receives during the course of ERCOT's day-to-day operations and that may have commercial impacts on the market for energy, Ancillary Services or transmission cost.

To the extent practicable, ERCOT shall post on the MIS information requested by Market Participants but not required to be posted by these Protocols.

12.3 Transmission-Related Information

ERCOT shall post to the Market Information System (MIS) transmission related information, including information pertaining to Transmission Congestion Rights (TCRs), Commercially Significant Constraint (CSC) capabilities, ERCOT standards and procedures, and the matrix of Congestion Zone Shift Factors used to calculate CSC impacts. ERCOT shall also post information related to full interconnection requests as set forth in Section 1.3.1.2, Items Not Considered Protected Information, no less than once per month.

Within ten (10) Business Days of executing a generation Interconnection Agreement, the Transmission Service Provider (TSP) shall provide a copy to ERCOT.

12.3.1 Transmission Congestion Rights

Upon commencement of TCR Auctions, ERCOT shall post to the ERCOT MIS all information that is commercially relevant to participation in the annual and monthly TCR Auctions.

12.3.2 Commercially Significant Constraint (CSC) Capabilities

Information pertaining to CSC capabilities shall include:

(1) The methodologies used by ERCOT to calculate the CSC capabilities;

(2) Current transfer capability limit of each CSC for the Operating Day and the Day Ahead Period;

(3) Summaries of any proposed or pending changes to the Congestion Zone, which ERCOT shall post at least ninety (90) days prior to the date when such change may be effective;

(4) Current total CSC costs incurred relative to the postage stamp threshold amount;

(5) The total MW of Replacement Reserve Service (RPRS) procured for the management of Zonal Congestion and Local Congestion; and

(6) Transmission Facility Outage information as set forth in Section 8, Outage Coordination.

12.3.3 ERCOT Standards and Procedures

ERCOT shall post on the MIS its standards and procedures.

12.3.4 Matrix of Congestion Zone Shift Factors

At least annually, ERCOT shall calculate a matrix of Shift Factors for energy exchange between Congestion Zones as set forth in Section 7, Congestion Management. ERCOT shall post these matrices on the MIS as the calculation of each matrix is completed.

12.3.5 Analysis of Resource Adequacy

12.3.5.1 Calculation of Aggregate Generating Capacity

ERCOT shall use Planned Outages submitted by Resource Entities pursuant to Section 8.1, Planned Outages and Maintenance Outages of Transmission and Resource Facilities, to calculate the aggregate capacity from Resources projected to be available in each Congestion Zone. On a rolling twelve (12) month basis, ERCOT shall calculate the aggregate weekly Resource capacity by Congestion Zone projected to be available during the peak Load hours of each week of the following twelve (12) months.

12.3.5.2 System Adequacy Report

On a rolling twelve (12) month basis, ERCOT shall analyze system adequacy for the ERCOT System and each Congestion Zone, comparing the minimum aggregated weekly peak Resource capacity to the weekly peak forecast Demand for the next twelve (12) months.

ERCOT shall report projected peak Resource capacity deficiencies to Market Participants. ERCOT shall update this report monthly using the latest Resource Planned Outages. ERCOT shall post the report on the MIS. The information published in the report shall include an indication of deficiency, if any, projected to occur in each Congestion Zone during each week of the rolling twelve (12) month period.

12.4 Market-Related Information

Market related information includes scheduling information, information related to Ancillary Services, current ERCOT System conditions, and long-term forecasts of ERCOT System conditions.

12.4.1 Scheduling Information

ERCOT shall post on the MIS scheduling information, based on requirements as set forth in these Protocols, including:

(1) ERCOT prepared demand forecasts;

(2) ERCOT forecasted CSC Capabilities and Congestion;

(3) As close to Real Time as practicable for each Congestion Zone, where applicable, power deployed with Regulation Reserves, Responsive Reserve, Non-Spinning Reserves and/or Balancing Energy and Market Clearing Prices for Energy;

(4) Day-Ahead Scheduling Process summaries, including total scheduled Load, total forecasted Load, and net transfer on each DC-tie;

(5) Commercially significant information, other than Protected Information, regarding changes in ERCOT System conditions, including changes or potential changes in the status of CSC capabilities; or conditions such as adverse weather conditions as determined from the ERCOT designated weather service, that could affect the security of the ERCOT System; and

(6) All forecasted Transmission Loss Factors and Distribution Loss Factors.

12.4.2 Ancillary Service -Related Information

ERCOT shall post on the MIS its Ancillary Services requirements as set forth in Section 4, Scheduling.

As set forth in Section 4, Scheduling, ERCOT shall post as specified in these Protocols, Day-Ahead Ancillary Services scheduling process hourly summaries, including:

(1) Amount of capacity procured and the MCPCs for each Ancillary Service;

(2) Notices of system insufficiencies;

(3) The quantities and prices of Ancillary Services acquired under conditions of system insufficiency (OOMC); and

(4) The quantities and prices of RMR Services.

ERCOT shall securely post information affecting the allocation of Ancillary Services to QSEs including:

(1) Each QSE's historical Load Ratio Share used for the Ancillary Services allocation; and

(2) Each QSE's allocation of each Ancillary Service based upon the information in (1) above.

12.4.3 Other Commercially-Significant Information

ERCOT shall post to the MIS all known elements of ERCOT charges that will not result in an unauthorized Disclosure of Protected Information, as defined in Section 1.3.1, Restrictions of Protected Information. Such information includes the elements of UFE determination, Local Congestion, and other ERCOT Postage Stamp Allocation charges.

12.4.4 Current System Conditions

ERCOT shall post on the MIS information, other than Protected Information, available to ERCOT including:

(1) The status of the ERCOT Transmission Grid,

(2) ERCOT's system-wide Load forecast,

(3) ERCOT's Ancillary Service requirements,

(4) Amounts of Ancillary Services arranged by ERCOT along with the MCPC for Ancillary Services,

(5) Deemed actual Transmission Loss Factors,

(6) Approved and proposed Transmission System Planned Outage information as set forth in Section 8, Outage Coordination;

(7) Security violations from contingency analysis, dynamic security analysis (DSA), and voltage security analysis (VSA) cases;

(8) ERCOT's Load flow results and network models (i.e., option for data transport via some electronic means).

(9) The quantities and prices of RMR Services deployed by ERCOT; and

(10) Total ERCOT System Load, real-time, integrated over intervals.

ERCOT shall post this information at the close of the Day-Ahead, Adjustment Period and Real Time markets. Market Participants shall provide ERCOT with data needed to reliably operate the ERCOT System and market functions.

The following data flow requirements include the minimum data Market Participants will furnish to ERCOT for reliable operations, as described in Section 12.4.4.1, ERCOT Power Operations and the minimum data ERCOT will furnish to Market Participants for market operations purposes, as described in Section 12.4.4.2, ERCOT Market Operations. Details regarding the format of data posted by the Market Participants and ERCOT can be found in the Operating Guides.

12.4.4.1 ERCOT Power Operations

12.4.4.1.1 QSE, Resource and TDSP Responsibilities

QSEs, Resources and TDSPs are required to provide power operation data to ERCOT including, but not limited to:

(1) Real time generation data from QSEs;

(2) Planned Outage information from Resources;

(3) Network data used by any TDSP's control center, including:

 (a) Breaker and line switch status of all ERCOT Transmission Grid devices;

(b) Line flow MW and MVAR;

(c) Breaker, switches connected to all Resources;

(d) Transmission Facility Voltages; and

(e) Transformer MW, MVAR and TAP.

(4) Real time generation and Load acting as a Resource meter data from QSEs;

(5) Real time Generation meter splitting signal from QSEs;

(6) Planned Transmission Outage information from TDSP;

(7) Network transmission data (model and constraints) from TDSP;

(8) Resource Plans from QSE; and

(9) Dynamic Schedules from QSEs;

Real Time data will be provided to ERCOT at the same scan rate as the TDSP or QSE obtains the data from telemetry.

12.4.4.1.2 ERCOT Responsibilities

ERCOT is required to provide the following power operation data to TDSPs, in accordance with confidentiality as defined in Section 1.3, Confidentiality, of these Protocols:

(1) Relevant information for the purpose of providing reliability as determined by ERCOT, including but not limited to:

(a) Status of any breakers and switches in ERCOT's Real Time data base;

(b) State estimator solutions;

(c) Transmission line flows and voltages;

(d) Transformer information;

(e) QSE Resource data; and

(f) Voltage schedules at major transmission busses;

(2) Interval meter data for Load and generation. This data shall include meter data measured at points of injection and points of delivery which will measurably impact the TDSP's planning and operations as determined by ERCOT Staff (e.g., determination of TDSP's system Load or power flows).

ERCOT will give notice to the Entities supplying the above list of data to ERCOT upon the initial provision of such data to the TDSP.

12.4.4.2 ERCOT Market Operations

12.4.4.2.1 QSE Responsibility

QSEs are required to provide market operation data to ERCOT including but not limited to:

(1) Ancillary Services bids, if any;

(2) Balanced Schedules;

(3) AS Schedules, including Self Arranged AS;

(4) AS award acknowledgment.

12.4.4.2.2 TDSP Responsibility

TDSPs are required to provide market operation data to ERCOT including but not limited to:

(1) Retail consumption data;

(2) Transmission Outage requests;

(3) Any system limitations information including but not limited to line limits;

(4) New or updated Premise level (ESI ID) information;

(5) Planned T&D construction information, including CCN application milestone dates if applicable, all of which shall be updated quarterly according to a schedule established by ERCOT; and

(6) Project status updates of Transmission Facilities that are part of an RMR or 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.

12.4.4.2.3 ERCOT Responsibility

ERCOT shall post both secure QSE specific market operation data and public information as follows:

12.4.4.2.3.1 Secure ERCOT Posting

ERCOT is required to securely provide QSE specific market operation data to each QSE, including but not limited to:

(1) QSE AS Obligation and requirements;

(2) AS award messages;

(3) LSE Load Ratio Share by Congestion Zone;

(4) Instructed Ancillary Services deployment;

(5) Resource, including Load acting as a Resource, meter data from ERCOT metered Entities;

(6) Aggregated retail Load data received by ERCOT from TDSP;

(7) Settlement data for billing determinants;

(8) Settlement Statements;

12.4.4.2.3.2 Public ERCOT Posting

ERCOT is required to provide market operation data to the public including but not limited to:

(1) Ancillary Service Plan;

(2) Notification of intent to procure RPRS;

(3) Notification of intent to procure additional Ancillary Services;

(4) CSC Limits and forecasted Congestion;

(5) Aggregated retail Load by Congestion Zone;

(6) System loss information;

(7) UFE data;

(8) Commercial and operational Congestion notification to market;

(9) ERCOT Load forecast, by Load area, Congestion Zone, and system;

(10) Errors to Market Participants and system logs, without violating Subsection 1.3.1, Restrictions on Protected Information;

(11) Forecasted and Actual Load Profiles;

(12) ESI ID and related information from registration for validation and information posting; and

(13) Within two (2) days after the applicable Operating Day, but no earlier than the applicable Operating Day, aggregated data for each Settlement Interval (if applicable) and Congestion Zone (if applicable), for the following:

(a) Quantities and prices of hourly bids for Balancing Energy and each type of capacity Ancillary Service, in the form of supply curves;

(b) Self-arranged Ancillary Services, for each type of service, by hour;

(c) Self-arranged Energy Schedules;

(d) Actual Resource output;

(e) Final metered dynamic Load and Resource output. This data may be aggregated for the entire ERCOT Region if necessary to ensure that individual QSE information remains protected; and

(f) Scheduled Load and actual Load.

12.4.4.2.3.3 Public Posting of Entity-Specific Market Reports

(1) Seven (7) days after the applicable Operating Day, ERCOT shall publicly post on its MIS the Schedule Control Error, as calculated by ERCOT and integrated over each Settlement Interval, for each QSE for each Settlement Interval of the applicable Operating Day.

(2) Sixty (60) days after the applicable Operating Day, ERCOT shall post portfolio offer curves for Balancing Energy service and each type of Ancillary Service, for each area where available.

(3) Forty-eight (48) hours after the applicable Operating Day, ERCOT shall post the bid price and the name of the QSE submitting the bid for the highest-priced bid selected or dispatched by ERCOT for Balancing Energy service and each Ancillary Service, for each area where available.

(4) If the Market Clearing Price for Energy (MCPE) or the MCPC expressed in dollars per MWh or dollars per MW per hour ("Trigger Price") exceeds fifty (50) times the Houston Ship Channel natural gas price index for any Settlement Interval in an Operating Day, the portion of any QSE's bid for Balancing Energy service or any other Ancillary Service

that is at or above the Trigger Price for the applicable Settlement Interval shall be posted seven (7) days after the day for which the bid was submitted.

(5) Sixty (60) days after the applicable Operating Day, ERCOT shall post the following by Settlement Interval and area, where available:

(a) Final energy schedules for each QSE;

(b) Final Ancillary Services schedules for each QSE;

(c) Resource Plans for each Resource represented by a QSE;

(d) Actual output from each Resource;

(e) All Dispatch Instructions from ERCOT for Balancing Energy and Ancillary Services; and

(f) Load and Generation Resource output for each Congestion Zone for each QSE that dynamically schedules its Resources.

The information posted shall include the names of the Resources in the portfolio that were committed, the names of the Entities submitting the information, and the names of the Entities controlling each Resource in the portfolio. ERCOT shall determine the Entity in control of each Resource in accordance with subsection (e) of P.U.C. SUBST. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas.

(6) One hundred and eighty (180) days after the applicable Operating Day, ERCOT shall post Adjusted Metered Load for each QSE, by Congestion Zone and by Settlement Interval; and

(7) To the extent that the data initially posted pursuant to the requirements of this subsection are subject to change in subsequent ERCOT settlement operations, ERCOT shall provide for incremental posting of each subsequent settlement operation as it affects the items required to be posted in this subsection within seven (7) days of the completion of any subsequent settlement operation. Data related to the initial posting and all subsequent settlement operations shall remain accessible for a period of at least twenty-four (24) months following the applicable Operating Day. Notwithstanding the foregoing, ERCOT is not required to update the data.

12.4.4.2.3.4 Non-Mandatory Public ERCOT Posting

ERCOT may also post the following types of information on the MIS, including, but not limited to:

(1) Public domain data available for public access through the Internet;

(2) Public domain data from PUCT's market oversight activities;

(3) Various market reports;

(4) Relevant regulatory documents; and

(5) Relevant Public notices.

12.4.4.3 Public Access to Declassified Information

Information that is declassified as Protected but not posted, including Dispatch Instructions, shall be available upon request in accordance with ERCOT Request for Records and Information Policy. Requested information will be provided within a reasonable timeframe at no cost to the requestor. For Dispatch Instructions the information may be requested by Congestion Zone and by 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.

12.4.5 Long-Term Forecasts of ERCOT System Conditions

ERCOT shall post its long-term forecasts of ERCOT System conditions as required by Section 8, Outage Coordination including:

(1) Monthly forecasts of demand by Congestion Zone for each of the next twelve (12) months by week;

(2) Monthly forecasts of insufficiencies by Congestion Zone for each of the next twelve (12) months by week;

(3) Approved Planned Transmission System Outages for each of the next twelve (12) months by week;

(4) Other information, other than Protected Information, related to system conditions of commercial relevance to Market Participants.

12.4.6 Timing of Market-Related Information Posting

ERCOT shall post all historical data relating to an Operating Day before the end the last Business Hour of the day after the Operating Day.

12.5 Applicable Reliability Standards

ERCOT shall post on the MIS its reliability standards and all amendments, revisions and updates thereto.

ERCOT Protocols
Section 13: Transmission and Distribution Losses

January 1, 2009

13 TRANSMISSION AND DISTRIBUTION LOSSES

13.1 Overview

This section sets forth the method for calculating Transmission and Distribution Losses (T&D Losses) and responsibilities of ERCOT, Qualified Scheduling Entities (QSEs), and Transmission and/or Distribution Service Providers (TDSP) with respect to T&D Losses.

13.1.1 Responsibility for Transmission and Distribution Losses

T&D Losses are the responsibility of the QSE representing the Competitive Retailer's Load. The QSE will schedule the necessary amount of energy to cover Competitive Retailer's Load plus the applicable T&D Losses. 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.

Transmission Loss Factors shall be forecasted by ERCOT, and posted to the MIS by 0600 of the Day Ahead period. ERCOT shall forecast the ERCOT-wide Transmission Loss Factors expressed as a percent of Load for each settlement interval of the Operating Day. On the day following the Operating Day, ERCOT shall also calculate Transmission Loss Factors for each Settlement Interval using actual ERCOT System Load for that Settlement Interval and will post the resulting deemed actual Transmission Loss Factors to the settlement system and the MIS.

Distribution Loss Factors (DLF)shall be forecasted by ERCOT, and posted to the MIS by 0600 of the Day Ahead period. ERCOT shall forecast the DLFs expressed as a percent of Load for each Settlement Interval of the Operating Day.

On the day following the Operating Day, ERCOT shall also calculate DLFs for each Settlement Interval using actual ERCOT System Load for that Settlement Interval and post the resulting deemed actual DLFs to the settlement system and the MIS.

DLFs will be subject to audit by ERCOT for accurate and consistent application. Non-Opt-in Entities (NOIE) with Interval Data Recorders at the settlement point of delivery are not required to provide DLFs.

In the special case where there are distribution Facilities upstream from a wholesale NOIE 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 will be then treated as a transmission level NOIE. Calculations are subject to review by ERCOT. Since loss compensation is included in the wholesale settlement IDR, the TDSP 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

ERCOT shall use the deemed actual DLFs applicable to each ESI ID and the deemed actual Transmission Loss Factors when adjusting aggregated Load for losses to determine the QSE total Load obligations.

13.2 Transmission Losses

13.2.1 Forecasted Transmission Loss Factors

The forecasted Transmission Loss Factor for each interval in the Operating Day shall be a linear interpolation or extrapolation using the on-peak and the off-peak Transmission Loss Factors and the corresponding forecast of ERCOT System Load during the same interval to calculate the loss factors.

At 0600 of the Day Ahead period, ERCOT shall forecast a Transmission Loss Factor for each Settlement Interval of the Operating Day and post the forecasted Transmission Loss Factors 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.

13.2.2 Deemed Actual Transmission Loss Factors

ERCOT will determine the deemed actual Transmission Loss Factor for each interval in the Operating Day, by use of a linear interpolation or extrapolation using the on-peak and the off-peak Transmission Loss Factors corresponding to the actual ERCOT System Load for the interval.

The day after the Operating Day, ERCOT shall calculate deemed actual Transmission Loss Factors for each Settlement Interval of the Operating Day and post the Transmission Loss Factors to be used in settlement calculations.

ERCOT shall use the Transmission Loss Factors 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 Transmission Loss Factors. ERCOT will post Transmission Loss Factors to the MIS by 0600 two (2) days after the Operating Day.

13.2.3 Transmission Loss Factor Calculations

The following formulas shall be used to translate the seasonal on-peak and off-peak Transmission Loss factors into Settlement Interval Transmission Loss Factors.

$$\mathbf{TLF_i \quad = \quad (SSC * SIEL_i) + SIC}$$

Where:

i =	interval
TLF_i =	Transmission Loss factors for a settlement interval
$SIEL_i$ =	Settlement Interval ERCOT System Load (forecasted or actual)
SSC =	Seasonal Slope Coefficient
SIC =	Seasonal Intercept Coefficient

And,

SSC = (SONLF – SOFFLF)/(SONL-SOFFL)

SIC = [(SOFFLF*SONL)-(SONLF*SOFFL)]/(SONL-SOFFL)

Where:

SONLF =	Seasonal on-peak percent loss factor
SOFFLF =	Seasonal off-peak percent loss factor
SONL =	Seasonal on-peak Load value
SOFFL =	Seasonal off-peak Load value

13.2.4 Seasonal Transmission Loss Factor Calculation

Seasonal on-peak and off-peak Transmission Loss Factors are derived from 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:

(1) Spring (March – May)

(2) Summer (June – August)

(3) Fall (September – November)

(4) Winter (December – February)

ERCOT shall calculate seasonal Transmission Loss Factors by dividing ERCOT seasonal case transmission losses (60 kV system and higher) by ERCOT seasonal base Load adjusted (reduced) for self serve Load modeled in the case. The resulting loss factors are expressed as a percentage of Load.

ERCOT shall post, to the MIS, seasonal Transmission Loss Factors thirty (30) days prior to the start of the season.

13.2.5 Loss Monitoring

ERCOT shall monitor Transmission Losses annually and will investigate abnormal loss factors. ERCOT and Transmission Service Providers shall use the cost of losses as one criterion in evaluating the need for transmission additions.

13.3 Distribution Losses

By October 30th of each year for the next calendar year, or two (2) months prior to the posting of any update to the approved Distribution Loss Factor (DLF) codes and calculation each Distribution Service Provider (DSP), except NOIEs, shall calculate and provide ERCOT the Annual DLFs to be applied to distribution voltage level Loads in its area of certification. ERCOT shall review and approve the DLF calculation methodology used by each DSP prior to use of the loss factors 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 DLF and the calculation methodology will be posted, and the last approved DLFs 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 based on the DSP internal evaluation.

The TDSP shall assign a DLF code to each ESI ID. A maximum of five (5) DLFs may be submitted for each DSP based upon ERCOT approved parameters, such as service voltages or number of transformations.

The following coding standards will be used to identify the DLF applicable to each ESI ID:

- T = Transmission connected Customers (no Distribution Loss Factor applied)
- A through E = TDSP defined Customer segment(s)

The DSPs, except NOIEs, are obligated to provide DLFs to ERCOT. ERCOT will post the DLF and calculation methodology, including any equations and constants, for each DSP.

Loss factor variables submitted by the DSP shall include:

(1) The annual DLF coefficients (F_1, F_2, and F_3) for each DLF code; and

(2) The methodology upon which the calculation of the coefficients (F_1, F_2, and F_3) was made.

13.3.1 Loss Factor Calculation

ERCOT shall use the DLFs submitted by the DSP to calculate the Settlement Interval DLFs. DLFs will be calculated from the data provided by DSPs as follows using the following equation:

$$\mathbf{SILF_i = F_1 * (SIEL_i/AAL) + F_2 + F_3 / (SIEL_i/AAL)}$$

Where:

i =	interval
$SILF_i$ =	Settlement Interval DLF
$SIEL_i$ =	Settlement Interval ERCOT System Load (forecasted or actual)
AAL =	Annual Interval Average ERCOT System Load (forecasted or actual)
F_1, F_2, F_3 =	Coefficients determined by the DSP to allow calculation of its SILF from ERCOT System Load

ERCOT shall use the deemed actual DLFs calculated for each Settlement Interval of the Operating Day for settlement purposes.

13.3.2 Loss Monitoring

DLFs for all Distribution Service Providers, 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

All QSEs representing Load, including 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.

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 corresponding to the actual NOIE system Load in the interval.

ERCOT shall calculate seasonal NOIE Transmission Loss Factors corresponding to the on-peak and off-peak base case NOIE system Loads during each of the four (4) seasons of the upcoming year as the basis for the NOIE Transmission Loss Factors. NOIE seasonal loss factors will be calculated in the same manner as the loss factors are calculated for the ERCOT wide Transmission Loss Factors.

ERCOT Protocols
Section 14: State of Texas Renewable Energy Credit Trading Program

August 1, 2009

14 STATE OF TEXAS RENEWABLE ENERGY CREDIT TRADING PROGRAM

14.1 Overview

On May 9, 2000, the Public Utility Commission of Texas (PUCT) appointed ERCOT as Program Administrator of the Renewable Energy Credit (REC) Trading Program as described in subsection (g) of P.U.C. Subst. R. 25.173, Goal for Renewable Energy.

The purposes of the REC Trading Program are: 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; 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 to ensure that all Customers have access to providers of energy generated by renewable energy Resources pursuant to PURA §39.101(b) (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

As described in more detail in this Section, ERCOT shall:

(1) Register renewable energy generators;

(2) Register offset generators;

(3) Register Retail Entities;

(4) Register other Entities choosing to participate in the Renewable Energy Credit (REC) Trading Program;

(5) Create and maintain REC trading accounts for program participants;

(6) Determine the annual Renewable Portfolio Standard (RPS) requirement for each Retail Entity in Texas using the formulas set forth in this Section;

(7) On a quarterly basis, award RECs or Compliance Premiums earned by REC generators based on verified MWh production data;

(8) Verify that Retail Entities meet annual REC compliance requirements;

(9) Retire RECs or Compliance Premiums as directed by program participants;

(10) Retire RECs or Compliance Premiums as they expire;

(11) On a monthly basis, make public the aggregated total MWh competitive energy sales in Texas;

(12) 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;

(13) 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);

(14) Conduct a REC Trading Program settlement process annually, starting in 2002 with voluntary settlements for the Customer Choice Pilot;

(15) 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;

(16) Monitor the operational status of all existing renewable energy Facilities in Texas and record retirements;

(17) Compute and apply a revised Capacity Conversion Factor (CCF) as described in Section 14.9.2, Capacity Conversion Factor, below) every two (2) years;

(18) Audit MWh production data from certified REC generating Facilities;

(19) Audit MWh production from Facilities producing offsets for Retail Entities on an annual basis;

(20) Post a list of Facility identification numbers, and the associated Facility name, location, type, and noncompetitive certification data on the Market Information System (MIS); and

(21) 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

ERCOT may conduct site visits to renewable energy generation Facilities on a random basis to ensure integrity of the program, as deemed necessary. ERCOT shall require each registered renewable energy generator to provide one (1) or more contact persons for purpose of site visit notification. ERCOT shall provide at least forty-eight (48) hours notice to the designated contact(s) prior to conducting a site visit for wind Resources only.

14.3 Creation of REC Accounts and Attributes of RECs

14.3.1 Creation of REC Accounts

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 trading accounts to execute a standard Agreement with ERCOT. Each party requesting a REC Account must name a "Designated Representative" and may name an additional contact person. A Designated Representative is a responsible natural person authorized by the owners or operators of a renewable Resource to register that Resource with ERCOT. The Designated Representative must have the authority to represent and legally bind the owners and operators of the renewable Resource 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 RECs and Compliance Premiums

A REC or Compliance Premium is a tradable instrument that represents all of the renewable attributes associated with one (1) 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.

Compliance Premiums are 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 energy portfolio standard requirements, one (1) Compliance Premium is equal to one (1) REC.

REC Information	Field Length	Description
Year	4 Digits	Year REC was issued
Quarter	1 Digit	Quarter REC was issued
Type of Renewable Resource	2 Characters	Abbreviated reference to type of renewable Resource
Facility Identification Number	5 Digits	Number to be assigned by ERCOT

REC Information	Field Length	Description
REC Number	8 Digits	REC Number 1 through the number of MWh generated by the Facility during the quarter.

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 thirty (30) days of such changes.

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.

A REC generated on or after January 1, 2002, will have an issue date of the Compliance Period in which it is generated. A "Compliance Period" is a calendar year beginning January 1 and ending December 31 of each year in which RECs are required of a Retail Entity.

RECs have a useful life of three (3) 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 (3) Compliance Periods for which this REC may be used are 2006, 2007, and 2008. This REC will expire one (1) 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 REC Generator or REC Aggregator

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 Facility is eligible to generate or an Entity is eligible to aggregate RECs, ERCOT shall establish a REC Account for the Facility or Entity. Each REC Account shall have a unique identification number.

After providing thirty (30) days notice to the REC Account Holder, ERCOT will close an account holding no RECs or Compliance Premiums for a period of one (1) year.

14.5 Reporting Requirements

14.5.1 REC Generators and REC Offset Generators

All Renewable Energy Credit (REC) generators and REC offset generators must report quarterly MWh production data to ERCOT no later than the thirty-eighth (38^{th}) 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:

(1) Renewable Resource Facilities located within ERCOT that have interval meters, pursuant to Section 10, Metering, and have interval metered generation data provided to ERCOT for energy settlement will have the quarterly reporting function performed on their behalf by ERCOT using the Settlement Quality Meter Data extracted from the ERCOT settlement system.

(2) REC aggregation companies 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.

(3) All other REC generators, not specifically covered in item (1) and item (2) 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.

(4) Entities certified to produce RECs from landfill gas supplied directly to a gas distribution system operated by a Municipally Owned Utility (MOU) shall report in writing the MWh equivalent production data and supporting calculations to ERCOT on a timeline prescribed by ERCOT.

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.

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 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

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 thirty-eighth (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:

(1) 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.

(2) 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.

(a) Entities reporting under paragraph (2) 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.

(b) 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 .

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.

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

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 RPS Requirement for Retail Entities, and Section 14.9.5, Final RPS Requirement, a transmission-level voltage Customer that wishes to have its Load excluded from RPS calculations pursuant to P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, must submit the information in accordance with the rule

14.6 Awarding of RECs

Following the end of each calendar quarter, 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, REC Generators and REC Offset Generators, and in Section 14.5.2, Retail Entities, ERCOT will credit RECs to the appropriate REC 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 REC Award Calculations

Adjustments (reductions) to REC awards are made for renewable Facilities that use more than two-percent (2.0%) fossil fuel, renewable Facilities that are repowered, and for REC aggregators that use estimation techniques to report generation.

Co-Fired Generator Adjustments

For REC generators using a renewable energy technology that requires the use of fossil fuel that is greater than two-percent (2.0%), and less than or equal to twenty-five percent (25%), of the total annual fuel input on a 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.

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;

Repowered Facility Adjustments

A "Repowered Facility" is 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. 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.

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.

$$\text{AdjustedMWh} = HO_q\ (150/NC)$$

Where:

HO_q = Total Production or Historical Output (HO) (MWh) by the Repowered Facility for quarter "q".

NC = Nameplate Capacity is the machine generation capacity posted on a specific piece of equipment or unit.

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 (1) REC for every 1.25 MWh generated.

14.6.2 Awarding of Compliance Premiums

A Compliance Premium is awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy source 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 (1) REC.

One (1) Compliance Premium shall be awarded for each REC awarded for energy generated after December 31, 2007.

14.7 Transfer of RECs or Compliance Premiums Between Parties

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 account to the account specified in the transfer request. Transfer requests received by ERCOT and confirmed by both Entities by 10:00 A.M. CST shall be effective the next Business Day.

If a request for transfer cannot be executed, ERCOT will notify the requesting Entities of the reason.

On completing a transfer, ERCOT shall notify the Designated Representatives of all involved account owners by e-mail.

For the purpose of the REC Trading Program, RECs or Compliance Premiums residing in an Entity's account are deemed to be owned by that Entity.

To the extent practicable, ERCOT will accommodate automated quarterly transfers.

14.8 REC Offsets

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 (G&T) cooperative, distribution cooperative, or an affiliate of a REP, MOU, G&T 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 an Existing Facility that may be used in place of a REC to meet a renewable energy requirement. "Existing Facilities" are renewable energy generators placed in service before September 1, 1999. REC offsets may not be traded.

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.

For purposes of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, a G&T 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 G&T cooperative will become responsible for the cumulative total of its distribution cooperatives' Renewable Portfolio Standards (RPS) requirements. The sharing of the REC offsets of the G&T 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 RPS Requirement Among Retail Entities

Beginning with the 2002 Compliance Period, and every Compliance Period thereafter through 2020, 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:

(1) 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.

(2) By the date set forth in P.U.C. SUBST. R. 25.173, the Program Administrator shall notify each Retail Entity of its total final Adjusted RPS Requirement (ARR) for the previous Compliance Period.

(3) By the date set forth in P.U.C. SUBST. R. 25.173, each Retail Entity must submit to the Program Administrator credits from its account equivalent to its final ARR for the previous Compliance Period.

(4) 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 RPS requirements.

14.9.1 Annual Capacity Targets

The renewable energy capacity targets (in MW) for each year are as follows:

Annual Capacity Target (MW)	Existing Renewable Capacity (MW)	Total Renewable Capacity Target (MW)	Compliance Period (Years)
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

ERCOT shall increase the new renewable energy capacity target for all future Compliance Periods to account for: (1) capacity producing REC from eligible qualifying out-of-state Facilities metered in Texas and, (2) capacity from Existing Facilities 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.

(Note: RECs may be produced by generators certified by the PUCT which are not located in Texas if: (1) the first metering point for such generation is in Texas, and (2) all generation metered at the location of injection into the Texas grid comes from that Facility. 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

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:

Individual Facility CCF_i $= (12/n) x \sum_{t=1}^{n} HO_{i,t} / (HC_{i,t} x 8760)$

Where:

i = Individual Facility

n = Number of months a specific Facility was in operation over the past twenty-four (24) months. n must be greater than or equal to twelve (12) and less than or equal to twenty-four (24).

$HO_{i,t}$ = Total production (MWh) by participating renewable generator i during Compliance Period t.

$HC_{i,t}$ = Average total generation capacity (MW) by participating renewable generator i during Compliance Period t.

and

$$CCF = \sum_{i=1}^{q} \left(CCF_i \ x \ PC_i \right) / \sum_{i=1}^{q} PC_i$$

Where:

q = The total number of REC Facilities in the program.

PC_i = Participating Capacity (MW) as of September 30 of the year the revised CCF is calculated for Facility i in the state of Texas participating in the REC Trading Program for which at least twelve (12) months of operating data are available.

The CCF shall:

(1) Be based on actual generator performance data for the previous two (2) years for all renewable Resources in the REC Trading Program during that period for which at least twelve (12) months of performance data are available.

(2) Represent a weighted average of generator performance; and

(3) Use all actual generator performance data that is available for each renewable Resource, excluding data for testing periods.

For purposes of calculating Historical Output (HO) from renewable capacity, ERCOT shall keep a list of renewable generators, REC certification dates, and annual MWh generation totals.

ERCOT shall use this revised CCF for the two (2) 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 Market Information System (MIS) within ten (10) Business Days of receipt of the letter from the PUCT.

14.9.3 Statewide RPS Requirement

ERCOT shall determine the SRR for a particular Compliance Period as follows:

$$SRR = (ACT\ (MW) \times 8760\ hr \times CCF) + RCP$$

Where:

ACT = Annual Capacity Target (MW) for new renewable Facilities.

8760 = The number of hours in a year.

CCF = Capacity Conversion Factor

RCP = The number of Compliance Premiums retired during the previous Compliance Period.

14.9.3.1 Preliminary RPS Requirement for Retail Entities

ERCOT shall determine each Retail Entity's preliminary RPS requirement as follows:

$$(\text{Preliminary RPS Requirement})_i = \text{SRR (MWh)} \times (\text{RESi (MWh)} / \text{TS (MWh)})$$

Where:

i = Specific Retail Entity

SRR = Statewide RPS Requirement

CRSRES_i = Retail sales of the specific Retail Entity (MWh) to Texas Customers during the Compliance Period, excluding sales by the specific Retail Entity to any Electronic 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 = Total retail sales of all Retail Entities (MWh) 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.

The sum of the preliminary RPS requirements for all Retail Entities shall be equal to the SRR.

14.9.4 Application of Offsets—Adjusted RPS Requirement

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 (FRR) to be zero (0). The total MWh reduction in the preliminary RPS requirement for all Retail Entities constitutes Total Useable Offsets (TUO).

ERCOT shall determine each Retail Entity's ARR as follows:

$$\text{ARR}_i = (\text{Preliminary RPS Requirement})_i - \text{EO}_i$$

Where:

i = Specific Retail Entity

EO_i = 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.)

ERCOT shall determine TUOs as follows:

$$TUO = SRR - \sum_{i=1}^{n} ARRi$$

Where:

i = Specific Retail Entity

n = Number of Retail Entities

SRR = Statewide RPS Requirement

ARR_i = Adjusted RPS Requirement for a specific Retail Entity.

14.9.5 Final RPS Requirement

ERCOT shall redistribute the TUO amount over all Retail Entities to determine the FRR. ERCOT shall determine each Retail Entity's FRR as follows:

FRR = $ARR_i + (TUO \times (RES_i / TS))$ +/- Previous Year(s) FRR Adjustment (recalculated in accordance with subsection (h) (3) of P.U.C. Subst. R. 25.173, Goal for Renewable Energy.

Where:

ARR_i = Adjusted RPS Requirement for a specific Retail Entity.

TUO = Total Usable Offsets

$CRSRES_i$ = Retail sales of the Retail Entity (in MWh) 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 = Total retail sales of all Retail Entities (in MWh) 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.

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.

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) (1) of P.U.C. SUBST. R. 25.173.

14.10 Retiring of RECs or Compliance Premiums

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 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 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

For each Compliance Period, beginning with the 2002 Compliance Period, by the date set forth for such notification 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 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 account until it is transferred to another party's account, expires, or is otherwise retired.

Failure to provide sufficient RECs or Compliance Premiums 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

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 RECs or Compliance Premiums

ERCOT shall retire all unused RECs and Compliance Premiums upon their expiration as described in Section 14.3.2, Attributes of RECs and Compliance Premiums.

14.11 Penalties and Enforcement

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 program.

14.12 Maintain Public Information

ERCOT shall maintain public information of interest to buyers and sellers of Renewable Energy Credits (RECs) or Compliance Premiums on the ERCOT Market Information System (MIS). 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:

(1) Name of the REC generator, Retail Entity, or other REC Account Holder;

(2) Name of the Designated Representative;

(3) Street address or post office box number;

(4) City, state or province, and zip or postal code;

(5) Country (if not the United States);

(6) Phone number;

(7) Fax number;

(8) E-mail address (with hypertext link); and

(9) Web site address (with hypertext link).

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 aggregation company, or other.

Entities are responsible for notifying ERCOT of changes in the above information.

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.

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) web site that are related to the REC Trading Program.

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.

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

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:

(1) MW of existing renewable capacity installed in Texas, by technology type;

(2) MW of new renewable energy capacity installed in Texas, by technology type;

(3) List of eligible non-Texas capacity participating in the program, by technology type;

(4) Summary of Renewable Energy Credit (REC) aggregation company activities, submitted in a format specified by the PUCT;

(5) Owner/operator of each REC generating Facility;

(6) Date each new renewable energy Facility began to produce energy;

(7) MWh of energy generated by renewable energy sources as demonstrated through data supplied in accordance with these Protocols;

(8) List of renewable energy unit retirements;

(9) List of all Retail Entities participating in the REC Trading Program;

(10) Final RPS Requirement (FRR) of each Retail Entity;

(11) Number of REC offsets used by each Retail Entity;

(12) A list of REC offset generators, REC offsets awarded and MWh production from each such generator on an annual basis;

(13) Number of RECs retired by each program participant by category (mandatory compliance, voluntary retirement, expiration, and total retirements);

(14) Number of Compliance Premiums retired by each program participant by category (mandatory compliance, expiration, and total retirements);

(15) List of all Retail Entities in compliance with Renewable Portfolio Standard (RPS) requirements; and

(16) List of all Retail Entities not in compliance with RPS requirements including the number of RECs by which they were deficient.

ERCOT Protocols

Section 15: Customer Registration

September 1, 2009

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15 CUSTOMER REGISTRATION

ERCOT shall maintain a registration database of all metered and unmetered Electric Service Identifiers (ESI IDs) in Texas for Customer Choice. ERCOT will track transactions and allocate costs of the registration database to the Market Participants (MPs).

ERCOT will immediately 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.

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.

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 MIS.

ERCOT will reject any initiating transaction due to date reasonableness if the requested implementation date is of more than ninety (90) days in the future or two hundred seventy (270) days in the past. Initiating transactions are: 814_01, Enrollment Request; 814_16, Move-In Request; and 814_24, Move-Out Request.

ERCOT will prioritize initiating or inbound transactions in the following manner:

(1) Level 1 – Priority 814_16, Move-In Requests, and 814_20, Create ESI ID Requests will be processed in one (1) Retail Business Hour.

(2) Level 2 – Standard 814_16, Move-In Requests, and 814_24, Move-Out Requests will be processed in two (2) Retail Business Hours.

(3) Level 3 – 867_02, Historical Usage, 814_20, Maintain ESI ID Requests, and 814_20, Retire ESI ID Requests will be processed in four (4) Retail Business Hours.

(4) Level 4 – All 814_01, Enrollment Requests, 814_26, Ad-hoc Historical Usage Requests, 814_18, Establish/Delete CSA CR Requests, and 814_19, Establish/Delete CSA CR Responses will be processed in one (1) Retail Business Day.

For transactions to flow through ERCOT, back-dated transactions for a market-approved corrective action must meet the date reasonableness test. MPs 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.

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

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

The CR shall submit a Switch Request to ERCOT using the 814_01, Enrollment Request. The Switch Request shall include, at a minimum, the five (5)-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 calculated starting with the date that ERCOT processes the 814_01 transaction sent by the CR. The online FASD calculator can be found on the Market Information System (MIS).

The FASD for a Switch Request is calculated as follows:

FASD = EPD + 3BD (Processing time)

Where:

EPD = ERCOT Processed Date
BD = Business Day (Does not include Transmission and/or Distribution Service Provider (TDSP) holidays.)

15.1.1.1 Notification to Customer of Switch Request

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.

A CR may cancel a switch at the request of the Customer or in accordance with PUCT rules. The CR will send such cancellation requests using the 814_08 transaction. ERCOT and the TDSP will accept cancellations until five (5) Retail Business Days preceding the scheduled meter read date.

[PRR819: Replace Section 15.1.1.1 above with the following upon system implementation:]

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

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

If requested by the switching CR in the Switch Request, the TDSP shall provide the most recent twelve (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 TSDP returning historical usage. Upon receipt of the historical usage from the TDSP, ERCOT shall forward it to the CR within four (4) Retail Business Hours.

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

To request historical usage on an ad hoc basis, the CR of Record must submit an 814_26, Ad-hoc Historical Usage Request, to ERCOT. Within one (1) 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 (2) Retail Business Days of receipt of the 814_26 transaction using the 814_27, Ad-hoc Historical Usage Response. ERCOT shall forward the usage information to the CR of Record using the 814_27 transaction within one (1) Retail Business Day of receipt of the 814_27 transaction from the TDSP. The TDSP shall provide the most recent twelve (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 within four (4) Retail Business Hours of receipt from the TDSP.

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 Registration Notification Request to TDSP

ERCOT will submit to the TDSP serving the ESI ID a registration Notification request using the 814_03, Switch CR Notification Request, within one (1) Retail Business Day 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

Upon receipt of a registration Notification request, the TDSP shall provide to ERCOT ESI ID information, including:

(1) ESI ID;

(2) Service Address;

(3) Rate class and sub-class, if applicable;

(4) Special needs indicator;

(5) Load Profile Type;

(6) Scheduled meter read date;

(7) Meter type, identification number, number of dials and role for each meter at the ESI ID, if ESI ID is metered;

(8) For unmetered ESI IDs, number and description of each unmetered device;

(9) Station ID; and

(10) Distribution Loss Factor (DLF) code.

This information shall be transmitted using the 814_04, Switch CR Notification Response, within two (2) Retail Business Days of the receipt of the 814_03, Switch CR Notification Request. If the TDSP does not respond with ESI ID information within two (2) 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 is received. If the TDSP's 814_04 transaction is not received by the earlier of the requested date on the switch (the FASD is used for standard switches) or within twenty (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 Switch Request. The TDSP will respond using the 814_09, Cancel Switch 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, Drop Due to Switch Request, has been sent will also receive Notification of the switch cancellation through the 814_08 transaction. The CR(s) will respond in accordance with the 814_09 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 (1) Retail Business Day.

15.1.1.5 Response to Valid Switch Request

Within one (1) Retail Business Day of receipt of the TDSP's 814_04, Switch CR Notification Response, ERCOT will respond to the requesting CR in accordance with the 814_05, Switch 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 (2) Retail Business Days of the scheduled meter read date.

15.1.1.6 Notification to Current CR of Drop Due to Switch (with date)

Within five (5) Retail Business Days of the scheduled meter read date for the switch, but not before the receipt of the TDSP's 814_04, Switch CR Notification Response, ERCOT will notify the current CR using the 814_06, Drop Due to Switch Request. This Notification will contain the scheduled meter read date for the switch. The current CR will respond to ERCOT within two (2) Retail Business Days with an 814_07, Drop Due to Switch Response. ERCOT continues processing the switch irrespective of receipt of the 814_07 transaction.

[PRR819: Replace Section 15.1.1.6 above with the following upon system implementation:]

Within two (2) Retail Business Days of the scheduled meter read date for the switch, but not before the receipt of the TDSP's 814_04, Switch CR Notification Response, ERCOT will notify the current CR using the 814_06, Drop Due to Switch Request. This Notification will contain the scheduled meter read date for the switch. The current CR will respond to ERCOT within two (2) Retail Business Days with an 814_07, Drop Due to Switch Response. ERCOT continues processing the switch irrespective of receipt of the 814_07 transaction.

15.1.1.7 Completion of Switch Request and Effective Switch Date

A Switch Request is effectuated on the actual meter read date in the 867_04, Initial Meter Read Notification, or the final 867_03, Monthly 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 (3) 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 and initial meter read information to the new CR using the 867_03 transaction and 867_04 transaction as appropriate. Meter reads received by 1800 will be available to the CR by 0600 the next day.

Use of the 814_28, Completed Unexecutable or Permit Required, is reserved for move-ins and move-outs only.

Failure by ERCOT to provide the initial meter read information does not change the effective date of the switch.

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

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, Enrollment Reject Response, within one (1) Retail Business Day of ERCOT's receipt of the Switch Request, and the switch process will terminate.

ERCOT will reject a Switch Request using the 814_02 transaction for any of the following reasons:

(1) The ESI ID provided is inactive or does not exist;

(2) The ESI ID and five (5)-digit zip code do not match;

(3) The CR is not certified by the PUCT, if required;

(4) The CR is not authorized to provide service in the TDSP service area;

(5) The CR has not registered as a CR with ERCOT in accordance with Section 16, Registration and Qualification of Market Participants;

(6) The PUCT directs ERCOT to reject registration requests from the CR per applicable PUCT rules;

(7) The standard Switch Request was received after a valid standard Switch Request was scheduled for the same date;

(8) 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);

(9) The CR submits a Switch Request type that is invalid or undefined;

(10) 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;

(11) The Customer Notification name or address is required but invalid according to Texas Standard Electronic Transaction (TX SET) standards or is missing;

(12) The CR DUNS Number (DUNS #) is missing or invalid;

(13) If requesting a self-selected switch date, the CR requests a switch date that is before the FASD;

(14) The date on the self-selected switch already has a move-in, move-out, or switch scheduled; or

(15) 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

ERCOT will send a reject response using the 814_11, Drop Response, within one (1) Retail Business Day to the current CR notifying the CR that the request is invalid.

15.1.3 Mass Transition

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.

In a Mass Transition event, ERCOT shall submit the 814_03, Switch CR Notification Request, requesting an off-cycle meter read for the associated ESI IDs, for a date two (2) 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 off-cycle meter read may be estimated by the TDSP. (See Retail Market Guide Section 9, Appendices, Appendix F2, Mass Transition Timelines.)

The TDSP shall respond to the 814_03 transaction within two (2) Retail Business Days with an 814_04, Switch CR Notification Response, and an 867_02, Historical Usage. Within one (1) 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 POLR or designated CR will respond using the 814_15, Drop Enrollment Response. The TDSP shall submit an 867_04, Initial Meter Read Notification, 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 D, Transaction Timing Matrix, for specific transaction timings.)

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 7.11, Mass Transition.

[PRR819: Replace Section 15.1.3 above with the following upon system implementation:]

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.

In a Mass Transition event, ERCOT shall submit the 814_03, Switch CR Notification Request, requesting a meter read for the associated ESI IDs, for a date two (2) 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, Mass Transition Timelines.)

The TDSP shall respond to the 814_03 transaction within two (2) Retail Business Days with an 814_04, Switch CR Notification Response, and an 867_02, Historical Usage. Within one (1) 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 POLR or designated CR will respond using the 814_15, Drop Enrollment Response. The TDSP shall submit an 867_04, Initial Meter Read Notification, 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 D, Transaction Timing Matrix, for specific transaction timings.)

ERCOT shall identify transitioned ESI IDs for a period of sixty (60) days 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 sixty (60) day period, whichever occurs first.

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 7.11, Mass Transition.

15.1.3.1 Customer Billing Contact Information

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.

For a detailed outline of the process, refer to the Retail Market Guide Section 7.11, Mass Transition.

15.1.4 Beginning Service (New Construction Completed and Move-Ins)

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.

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

The process described below relates to the transactions required to process a move-in. A manual work-around process for priority and safety net move-ins is also used by MPs 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.

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. If the Move-In Request is priority (depending on the TDSP tariff), the priority code is indicated in the 814_16 transaction. Priority move-ins will be forwarded to the TDSP within one (1) Retail Business Hour of receipt by ERCOT. Standard move-ins will be forwarded to the TDSP within two (2) Retail Business Hours of receipt by ERCOT.

Two (2) Retail Business Days prior to the scheduled meter read date of the move-in or upon receipt of the TDSP 814_04, Move-In CR 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, ERCOT shall cancel the move-out and send cancellation Notices to the TDSP and the respective CRs. ERCOT will submit an 814_06, Drop Due to Move-In Request, to the current CR with a code indicating a forced move-out.

If requested by the CR in the Move-In Request and permitted under the PUCT rules the TDSP shall provide up to twelve (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 TSDP returning historical usage. This information shall be provided to the CR within four (4) Retail Business Hours after ERCOT's receipt of the 867_02 transaction from the TDSP. The TDSP shall respond within two (2) Retail Business Days after receipt of the 814_03, Move-In CR Notification Request. If historical usage is not available, the TDSP will indicate this in the 814_04, Move-In CR Notification Response.

15.1.4.2 Response to Invalid Move-In Request

If the Move-In Request is invalid, ERCOT will respond to the CR using the 814_17, Move-In Reject Response, within one (1) Retail Business Hour of receiving the priority 814_16, Move-In Request, and within two (2) Retail Business Hours for standard move-ins, 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 forty-eight (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 TDSP of Move-In

ERCOT will process Move-In Requests upon receipt during Business Hours. ERCOT will submit to the TDSP serving the ESI ID a registration Notification request using the 814_03, Move-In CR Notification Request, within one (1) Retail Business Hour of receiving a valid priority Move-In Request and within two (2) Retail Business Hours for standard move-ins. 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.

If the TDSP receives the 814_03 transaction before 1700, a same-day move-in will be completed that day.

If the 814_16, Move-In Request, contains a priority code, the 814_03 transaction will contain priority codes which are defined on each TDSP website. ERCOT will expedite the processing of 814_16 transactions designated as same-day or priority move-ins.

15.1.4.4 Response to Registration Notification Request from TDSP (Move-In)

Upon receipt of a registration Notification request, the TDSP shall provide ESI ID information within the 814_04, Move-In CR Notification Response, including:

(1) ESI ID;

(2) Service Address;

(3) Rate class (if established*) and sub-class (if established*), if applicable;

(4) Special needs indicator;

(5) Load Profile Type;

(6) Scheduled meter read date;

(7) Meter type and role for each meter at the ESI ID, if ESI ID is metered;

(8) Identification number and number of dials for each meter at the ESI ID, if ESI ID is metered (if meter is present);

(9) For unmetered EDS IDs, number and description of each unmetered device (if devices are present*);

(10) Station ID;

(11) Distribution Loss Factor (DLF) code;

(12) Premise type; and

(13) 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, Maintain ESI ID Request, when established to complete the move-in. The TDSP must send the 814_20 transaction prior to sending the 867_03, Monthly Usage. ERCOT will neither hold transactions nor validate the order of receipt of these transactions prior to sending to the CRs.

If the TDSP does not respond with either the 814_04 transaction or the 814_28, Completed Unexecutable or Permit Required, within two (2) Retail Business Days after receiving the 814_03, Move-In CR 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, Permit Required, is not received within three (3) 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 twenty (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 Move-In Request. The TDSP will respond using the 814_09, Cancel Move-In Response, within one (1) 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. The relevant CRs will respond using the 814_09 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, Permit Required, within one (1) Retail Business Day.

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 item (1) of this Section shall be transmitted from the TDSP to ERCOT using the 814_04 transaction. ERCOT shall forward ESI ID/Premise information using the 814_05, Move-In Response, to the requesting CR.

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 (4) Retail Business Hours of receipt from the TDSP. The CR shall respond to ERCOT using the 814_21, Maintain ESI ID Response, within one (1) Retail Business Day after receipt of the 814_20 transaction.

If the TDSP responds to ERCOT's 814_03 transaction for a move-in with an 814_28, Permit Required, ERCOT shall send this transaction within two (2) 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 twenty (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.

The CR will respond to ERCOT using the 814_29, Response to Permit Required, within one (1) Retail Business Day of ERCOT submittal of the TDSP's 814_28 transaction. ERCOT shall pass the CR's 814_29 transaction to the TDSP within two (2) Retail Business Hours of receipt. After expiration of the twenty (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 twenty (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.

If the TDSP responds to ERCOT's 814_03 transaction with the 814_04 transaction and then later submits the 814_28, Completed Unexecutable, ERCOT will send the TDSP's 814_28 transaction to the requesting CR. The TDSP will note the completed 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. The CR will respond to ERCOT using the 814_29 transaction, and ERCOT shall pass the CR's 814_29 transaction to the TDSP.

The 814_29 transaction is used to notify the TDSP that the CR has received the 814_28 transaction. The CR is only allowed to reject the 814_28 transaction for invalid data. Neither the TDSP nor ERCOT changes the status of the initiating transaction upon receiving a reject of an 814_29 transaction.

If after submitting an 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 completed 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

ERCOT will respond to the CR using the 814_05, Move-In Response, within one (1) Retail Business Hour of receiving the TDSP's 814_04, Move-In CR Notification Response, on a priority Move-In Request and within two (2) Retail Business Hours for standard move-ins. 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 ESI ID with Meter Level Information Request/Response

If the TDSP returns the 814_04, Move-In CR 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, Maintain ESI ID 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 Notification, to ERCOT. ERCOT will forward the meter information in the 814_20 transaction and the 867_04 transaction to the CR.

When the CR receives the 814_20 transaction with the required information, it will respond back to ERCOT with the 814_21, Maintain ESI ID Response.

15.1.4.6 Notification to Current CR

An evaluation is done on the current CR two (2) Retail Business Days prior to the scheduled meter read date, but not before receipt of the TDSP's 814_04, Move-In CR Notification Response. ERCOT will submit to the current CR a Notification using the 814_06, Drop Due to Move-In Request, two (2) days before the scheduled meter read date as set forth in the 814_04 transaction. The current CR will respond using the 814_07, Drop Due to Move-In Response, within one (1) Retail Business Day after receipt of the 814_06 transaction.

If ERCOT has submitted a Notification using the 814_06 transaction to the current CR before the TDSP sends the 814_28, Completed Unexecutable, to ERCOT, ERCOT will notify the current CR by forwarding the 814_28 transaction to the CR. The current CR will respond using the 814_29, Response to Completed Unexecutable. The current CR will remain the CR of Record.

15.1.4.6.1 Completed Unexecutable

After the new CR has received the Premise information in the 814_05, Move-In 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, Completed Unexecutable. The transaction will indicate the appropriate reason code for the completion unexecutable of the Move-In Request. If the move-in has been completed unexecutable, ERCOT will internally flag the transaction as complete and will not expect the 867_04, Initial Meter Read Notification, to complete the life cycle. ERCOT will respond to the TDSP using the 814_29, Response to Completed Unexecutable.

If ERCOT receives the 814_28, Completed Unexecutable, 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.

Upon receipt of the 814_28 transaction, the new CR will respond to ERCOT using the 814_29 transaction.

15.1.4.7 Completion of Move-In Request and Effective Move-In Date

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 completed 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

A standard Move-In Request is effectuated on the period start date in the 867_04, Initial Meter Read Notification, which shall be the date requested in the 814_16, Move-In Request, provided that the 814_03, Move-In CR Notification Request, was received by the TDSP by 1700 at least two (2) Retail Business Days prior to the requested date. If the 814_03 transaction is not received by the TDSP by 1700 at least two (2) Retail Business Days prior to the requested date, the move-in will be completed within two (2) 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.

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 new CR within four (4) Retail Business Hours using the 867_04 transaction. The 867_04 transaction will be provided to ERCOT within three (3) Retail Business Days of the meter read.

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 received by ERCOT by 1800 will be available to the CR by 0600 the next day.

15.1.4.7.2 Priority Move-In Requests

A priority Move-In Request is effectuated on the period start date in the 867_04, Initial Meter Read Notification, 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 priority 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.

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 new CR within four (4) Retail Business Hours using the 867_04 transaction. The 867_04 transaction will be provided to ERCOT within three (3) Retail Business Days of the meter read.

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 received by ERCOT by 1800 will be available to the CR by 0600 the next day.

15.1.4.8 Rejection of Move-In Request

ERCOT will reject the 814_16, Move-In Request, using the 814_17, Move-In Reject Response, for any of the following reasons:

(1) The ESI ID provided is inactive or does not exist;

(2) The ESI ID and 5-digit zip code do not match;

(3) The CR is not certified by the PUCT, if required;

(4) The CR is not authorized to provide service in the TDSP service area.

(5) CR has not registered as a CR with ERCOT in accordance to Section 16, Registration and Qualification of Market Participants.

(6) The PUCT directs ERCOT to reject registration requests from the CR per applicable PUCT rules;

(7) The CR specifies a billing type or billing calculation code for an ESI ID that is not supported by the TDSP, MOU, or EC;

(8) The CR submits a request type that is invalid or undefined;

(9) The CR DUNS Number is missing or invalid;

(10) There is already a Move-In Request in progress for the same requested date, "not first in" for the same requested date; or,

(11) The move-in is received within two (2) Retail Business Days and is requesting a date that is within two (2) Retail Business Days of another scheduled move-in.

15.1.5 Service Termination (Move-Out)

15.1.5.1 Request to Terminate Service

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. 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 (CSA) CR Processing) using the 814_22, CSA CR Move-In Request within two (2) Retail Business Days of the scheduled meter read date, but not before the receipt of the TDSP's 814_04, Switch CR Notification Response. If there is not a CSA CR, ERCOT will notify the TDSP to de-energize the ESI ID.

15.1.5.2 Response to Invalid Move-Out Request

If the Move-Out Request is invalid, ERCOT will respond to the CR using the 814_25, Move-Out Response, within two (2) Retail Business Hours after receipt of the 814_24, Move-Out Request, from the CR 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 forty-eight (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 TDSP of Move-Out

ERCOT will process Move-Out Requests upon receipt during Business Hours.

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, Switch CR Notification Request, within two (2) Retail Business Hours after receipt of the valid Move-Out Request. The Notification will include the move-out date requested by the CR.

If there is not a CSA CR, ERCOT will notify the TDSP serving the ESI ID of the termination Notification 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 Registration Notification Request/Service Termination from TDSP

If there is a CSA CR, upon receipt of a registration Notification request, the TDSP shall provide ESI ID information, including:

(1) ESI ID;

(2) Service Address;

(3) Rate class and sub-class (if applicable);

(4) Any and all applicable riders;

(5) Special needs indicator;

(6) Load Profile Type;

(7) Scheduled meter read date;

(8) Meter type, identification number, number of dials and role for each meter at the ESI ID, if ESI ID is metered;

(9) For unmetered EDS IDs, number and description of each unmetered device;

(10) Load bus identification; and

(11) DLF code.

This information shall be transmitted by the TDSP using the 814_04, Switch CR 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 (2) Retail Business Days of the scheduled meter read date on the move-out to CSA. Items (1) and (7) 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 (2) Retail Business Days after the submission of the 814_03, Switch CR 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 (3) 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 twenty (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 Switch Request. The TDSP will respond using the 814_09, Cancel Switch Response. If the 814_09 transaction is an accept, relevant CRs will receive Notification of the cancellation through the 814_08 transaction. The relevant CRs will respond using the 814_09 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 (1) Retail Business Day.

If there is not a CSA CR, upon receipt of a service termination request, the TDSP shall provide ESI ID information, including:

(1) ESI ID; and

(2) Scheduled meter read date.

This information shall be transmitted using the 814_25 transaction and shall be provided by ERCOT to the submitting CR within two (2) Retail Business Hours from ERCOT's receipt of the TDSP's 814_25 transaction response. If the TDSP does not respond with ESI ID information within two (2) 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 (3) 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 twenty (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 Move-Out Request. The TDSP will respond in accordance with the 814_09, Cancel Move-Out 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 (1) Retail Business Day.

If the TDSP responds to ERCOT's 814_24 transaction with an 814_25 transaction and then later submits an 814_28, Completed Unexecutable, 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 completed unexecutable reason on the 814_28 transaction. The initiating transaction is considered unexecutable. Upon receipt of the 814_28 transaction, the CR will respond to ERCOT using the 814_29, Response to Completed Unexecutable. ERCOT shall pass the CR's 814_29 transaction to the TDSP. The current CR will remain the CR of Record.

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, Completed Unexecutable, and the TDSP shall note the completed unexecutable reason on the 814_28 transaction. ERCOT shall forward the 814_28 transaction to the CR within two (2) Retail Business Hours of receipt from the TDSP. The CR will respond to ERCOT within one (1) Retail Business Day of receipt of the 814_28 transaction using the 814_29, Response to Completed Unexecutable.

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.

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 thirty (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

Two (2) Retail Business Days prior to the scheduled meter read date, but not prior to the receipt of the TDSP's 814_04, Switch CR 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

A Move-Out Request is effectuated on the actual meter read date in the final 867_03, Monthly 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 (2) Retail Business Days prior to the date requested. If the request is not received by the TDSP by 1700 at least two (2) days prior to the requested date, the request will be completed within two (2) 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, Completed Unexecutable, to the CR.

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 (3) Retail Business Days of the meter read. Upon receipt, ERCOT will send final meter read information to the current CR and initial meter read information to the CSA CR (if applicable) within four (4) Retail Business Hours using the 867_03 transaction and 867_04, Initial Meter Read Notification, as appropriate.

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.

For a special meter read, the move-out is effective at 0000 (midnight) the day of the special meter read. Meter reads received by ERCOT by 1800 will be available to the CR by 0600 the next day.

15.1.5.7 Rejection of Move-Out Request

ERCOT will reject a Move-Out Request using the 814_25, Move-Out Response, for any of the following reasons:

(1) The ESI ID provided is inactive or does not exist;

(2) The ESI ID and 5-digit zip code do not match;

(3) The request type is invalid or undefined;

(4) The CR’s DUNS Number is missing or invalid;

(5) The requesting CR is not the current CR and not scheduled to be the CR on the requested date after a retry period of forty-eight (48) hours counting only hours on Retail Business Days but not only Business Hours;

(6) The move-out is received within two (2) Retail Business Days and requesting a date that is within two (2) Retail Business Days of another scheduled move-in or move-out; or

(7) The move-out is requesting a date that is scheduled on another move-out.

15.1.6 Concurrent Processing

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:

(1) Move-In Requests;

(2) Move-Out Requests; and

(3) Switch Requests. 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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.

15.1.6.3 Move-In Date Prior to or Equal to Switch Date

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

ERCOT performs evaluations two (2) 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

The CR will send a date change transaction using the 814_12, Date Change Request. ERCOT will accept date changes until the two (2) Retail Business Days preceding the scheduled move-in or move-out.

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 (2) 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 forty-eight (48) hours counting only hours on Retail Business Days, but not only Business Hours.

If the date change is accepted, ERCOT will notify the TDSP using the 814_12 transaction within two (2) Retail Business Hours of receipt of the 814_12 transaction from the CR. The TDSP will respond within two (2) 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. They will respond using the 814_13 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, Drop Due to Move-In Request, 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. Both CRs will respond using the 814_13 transaction within one (1) Retail Business Day of receipt of the 814_12 transaction.

15.1.8 Cancellation of Registration Transactions

The CR will send a cancellation Notice using the 814_08, Cancel Switch/Move-In/Move-Out/Mass Transition Drop Request. ERCOT will accept cancellations until two (2) Retail Business Days preceding the move-in or move-out date and five (5) Retail Business Days preceding a switch.

If the cancellation does not pass validation, ERCOT will reply to the CR within two (2) Retail Business Hours, with a rejection of the cancellation Notice using the 814_09, Cancel Switch/Move-In/Move-Out/Mass Transition Drop 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 forty-eight (48) hours counting only hours on Retail Business Days, but not only Business Hours.

If the cancellation Notice is accepted, ERCOT will set the status to 'cancel pending' status and notify the TDSP within two (2) 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, Drop Due to Switch/Move-In Request, 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 CRs and TDSP will respond using the 814_09 transaction.

[PRR819: Replace Section 15.1.8 above with the following upon system implementation:]

The CR will send a cancellation Notice using the 814_08, Cancel Switch/Move-In/Move-Out/Mass Transition Drop Request. ERCOT will accept cancellations until two (2) Retail Business Days preceding the move-in, move-out, or switch date.

If the cancellation does not pass validation, ERCOT will reply to the CR within two (2) Retail Business Hours, with a rejection of the cancellation Notice using the 814_09, Cancel Switch/Move-In/Move-Out/Mass Transition Drop 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 forty-eight (48) hours counting only hours on Retail Business Days, but not only Business Hours.

If the cancellation Notice is accepted, ERCOT will set the status to 'cancel pending' status and notify the TDSP within two (2) 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, Drop Due to Switch/Move-In Request, 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 CRs and TDSP will respond using the 814_09 transaction.

15.1.9 Continuous Service Agreement (CSA) CR Processing

This Section sets forth the processes to initiate or terminate a CSA.

15.1.9.1 Request to Initiate CSA

When a CR establishes a CSA at an ESI ID, the CR will send an 814_18 Establish CSA CR 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, Delete CSA CR Request, within one (1) Retail Business Day of receipt of the 814_18 transaction from the new CSA CR. The current CSA CR will respond using the 814_19, Delete CSA CR Response, within one (1) 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 transaction within one (1) Retail Business Day of receipt of the 814_18 transaction.

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 CSA

The CSA CR will send an 814_18, Delete CSA CR Request, to ERCOT. ERCOT will respond to the CR using the 814_19, Delete CSA CR Response.

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 CSA Competitive Retailer of Enrollment Due to a Move-Out

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 (2) Retail Business Days of the scheduled meter read date, but not before the receipt of the TDSP’s 814_04, Switch CR 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. The CSA CR will respond using the 814_23, CSA CR Move-In Response, within one (1) Retail Business Day of receipt of the 814_22 transaction.

If the CSA CR requires historical usage information for the ESI ID, the CSA CR will submit a request using the 814_26, Ad-hoc Historical Usage Request, after receipt of the 867_04, Initial Meter Read Notification.

15.1.9.4 Notice to CSA Competitive Retailer of Drop Due to a Move-In

An evaluation is done on the CSA CR two (2) Retail Business Days prior to the scheduled meter read date, but not before receipt of the TDSP’s 814_04, Move-In CR 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 Drop Due to Move-In Request. The CSA CR will respond using the 814_07, Drop Due to Move-In Response, within one (1) Retail Business Day.

If ERCOT has submitted a Notification using the 814_06 transaction to the CSA CR and then the TDSP sends the 814_28, Completed Unexecutable, to ERCOT, ERCOT will notify the CSA CR by submitting the 814_28 transaction. The CSA CR will respond using the 814_29, Response to Completed Unexecutable. The CSA CR will remain the CR of Record.

15.1.10 Continuous Service Agreement (CSA) CR Processing in MOU/EC Service Territory

This Section sets forth the processes to initiate or terminate a CSA in an MOU or EC service territory.

15.1.10.1 Request to Initiate CSA

When a CR establishes a CSA at an ESI ID, the CR will send an 814_18, Establish CSA CR Request, to ERCOT. This will be forwarded to the MOU/EC TDSP within one (1) Retail Business Day. ERCOT will send the 814_18 transaction, and if an 814_19, Establish CSA CR Response, is not received from the MOU/EC TDSP within ten (10) Business Days, ERCOT will cancel the CSA request and send an 814_08, Cancel Move-In 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 (1) Retail Business Day, and upon receipt of the 814_19 transaction (accept) from the MOU/EC TDSP, will send an 814_18, Delete CSA CR Request, to the current CSA CR and an 814_19, Establish CSA CR Response, to the new CSA CR within one (1) Retail Business Day of receipt of the 814_19 transaction from the MOU/EC TDSP.

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 CSA

The CSA CR will send an 814_18, Delete CSA CR Request, to ERCOT. Upon receipt of an 814_18 transaction, ERCOT will terminate the CSA relationship, send an 814_19, Delete CSA CR Response, to the CSA CR, and forward the 814_18 transaction to the TSDP. An 814_18, Delete CSA CR Request, received while an 814_18, Establish CSA CR Request, is pending will delete the current CSA relationship at ERCOT, provided the CSA CR of the 814_18, Delete CSA CR Request, and the current active CSA CR is the same.

If CSA CR wishes to terminate CSAs with multiple ESI IDs, the CSA CR must submit an 814_18, Delete CSA CR Request, for each ESI ID.

15.1.10.3 Notice to CSA Competitive Retailer of Enrollment Due to a Move-Out

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 (2) Retail Business Days of the scheduled meter read date, but not before the receipt of the MOU/EC TDSP's 814_04, Switch CR 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. The CSA CR will respond using the 814_23, CSA CR Move-In Response, within one (1) Retail Business Day of receipt of the 814_22 transaction.

If the CSA CR requires historical usage information for the ESI ID, the CSA CR will submit a request using the 814_26, Ad-hoc Historical Usage Request, after receipt of the 867_04, Initial Meter Read Notification.

15.1.10.4 Notice to CSA Competitive Retailer of Drop Due to a Move-In

An evaluation is done on the CSA CR two (2) Retail Business Days prior to the scheduled meter read date, but not before receipt of the MOU/EC TDSP's 814_04, Move-In CR 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, Drop Due to Move-In Request. The CSA CR will respond using the 814_07, Drop Due to Move-In Response within one (1) Retail Business Day.

If ERCOT has submitted a Notification using the 814_06 transaction to the CSA CR and then the TDSP sends the 814_28, Completed Unexecutable, to ERCOT, ERCOT will notify the CSA CR by forwarding the 814_28 transaction. The CSA CR will respond using the 814_29, Response to Completed Unexecutable. The CSA CR will remain the CR of Record.

15.2 Database Queries

Competitive Retailers (CRs) and aggregators may obtain information from ERCOT to determine or to verify the Electric Service Identifier (ESI ID) for a Service Delivery Point (SDP) using the Service Address. CRs or aggregators may also obtain information from ERCOT to determine or to verify the Service Address for an SDP, using the ESI ID through a look-up function on the Market Information System (MIS). This look-up function will return the following information for an SDP:

(1) Service Address;

(2) Meter read code;

(3) ESI ID;

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

(5) Premise type;

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

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

(8) Power region;

(9) Station ID;

(10) Metered/unmetered flag; and

(11) 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).

CRs or aggregators can also obtain information regarding the ESI IDs in a downloadable file. This file will contain the above listed information and is intended to be used to enable CRs and aggregators to incorporate ESI ID information into their database systems.

[PRR805: Replace Section 15.2 with the following, upon system implementation:]

15.2 Database Queries

Competitive Retailers (CRs) and aggregators may obtain information from ERCOT to determine or to verify the Electric Service Identifier (ESI ID) for a Service Delivery Point (SDP) using the Service Address. CRs or aggregators may also obtain information from ERCOT to determine or to verify the Service Address for an SDP, using the ESI ID through a look-up function on the Market Information System (MIS). This look-up function will return the following information for an SDP:

(1) Service Address;

(2) Meter read code;

(3) ESI ID;

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

(5) Premise type;

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

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

(8) Power region;

(9) Station ID;

(10) Metered/unmetered flag;

(11) 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); and

(12) Provisioned Advanced Metering System (AMS) meter flag.

CRs or aggregators can also obtain information regarding the ESI IDs in a downloadable file. This file will contain the above listed information and is intended to be used to enable CRs and aggregators to incorporate ESI ID information into their database systems.

15.3 Monthly Meter Reads

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 (3) 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 Usage. TDSPs shall send monthly consumption information for all ESI IDs associated with EPS metered Facilities to ERCOT no later than three (3) 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) within one (1) Retail Business Day.

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 (7) days in order to obtain a valid meter reading.

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 (7) days in order to obtain a valid meter reading.

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.

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 within one (1) Retail Business Day.

15.4 Electric Service Identifier (ESI ID)

Each Transmission and/or Distribution Service Provider (TDSP) Service Delivery Point (SDP) shall have a unique number within Texas. Once this unique number has been created and assigned to an SDP, 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).

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 SDP.

15.4.1 ESI ID Format

The ESI ID will have the following format:

10xxxxxyyy..yy

Where:

10	represents a placeholder for future use
xxxxx	is the 5-digit Department of Energy (DOE) identification code for the assigning TDSP
yyy..yy	is up to 29 alphanumeric characters assigned by the TDSP

Allowable alphanumeric characters are 0-9, A-Z, and the space character. The space character should only be used to right-pad the field when less than 29 characters are used. The total length of the ESI ID cannot exceed 36 alphanumeric characters.

It is the TDSP's responsibility to create, assign, maintain and retire, as necessary, an ESI ID to each SDP in its service area.

15.4.1.1 Assignment of ESI IDs to Unmetered SDPs

In general, each unmetered SDP 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 SDPs into one ESI ID provided they meet all of the following conditions:

(1) The SDPs 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);

(2) All SDPs have the same Usage Profile;

(3) All SDPs have the same voltage and are located in the same Unaccounted for Energy (UFE) zone, and same Load Zone; and

(4) The TDSP's tariffs allow aggregation of unmetered SDPs.

15.4.1.2 Assignment of ESI IDs to metered SDPs

In general, each metered SDP will be assigned an ESI ID corresponding to an existing billing meter. However, the TDSP may aggregate metered SDPs into one ESI ID provided they meet all the following conditions:

(1) The SDPs are owned by the same Customer and are at the same Service Address;

(2) All SDPs have the same Load Profile or all SDPs have Interval Data Recorders (IDRs);

(3) All SDPs have the same voltage and are located in the same UFE zone and same Load Zone; and

(4) The TDSP's tariffs allow aggregation of separately metered SDPs.

A Customer may request that the TDSP assign separate ESI IDs for separate SDPs as allowed in the TDSP's tariffs.

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 an SDP into Multiple ESI IDs

An SDP with Load above one (1) MW may split the actual meter into up to four (4) 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 ESI ID Creation

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 SDPs in their service territory.

The TDSP will send ESI ID information using the 814_20, Create ESI ID Request. ERCOT will verify that this transaction meets Texas Standard Electronic Transaction (TX SET) specifications. ERCOT will respond to the TDSP within one (1) Retail Business Hour, with acceptance or rejection of these transactions using the 814_21, Create ESI ID Response. At least the following data elements are required to be sent in the 814_20 transaction:

(1) ESI ID;

(2) Service Address; city, state, zip;

(3) Load Profile Type;

(4) Meter reading cycle or meter cycle by day of month;

(5) Station ID;

(6) Distribution Loss Factor (DLF) code; and

(7) Premise type.

15.4.1.5 ESI ID Maintenance

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, Maintain ESI ID Request. ERCOT will respond to the TDSP within four (4) Retail Business Hours, using the 814_21, Maintain ESI ID Response. In addition, ERCOT will send all affected CRs Notice of the changes using the 814_20 transaction. Each CR will reply to ERCOT using the 814_21 transaction within one (1) Retail Business Day. The TDSP is responsible for the following data elements:

(1) Service Address; city, state, zip;

(2) Load Profile Type;

(3) Meter reading cycle or meter cycle by day of month;

(4) Station ID;

(5) DLF code;

(6) Eligibility date;

(7) Meter type;

(8) Rate class and sub-class, if applicable;

(9) Special needs indicator;

(10) Meter type, identification number, number of dials and role for each meter at the ESI ID, if ESI ID is metered;

(11) For unmetered ESI IDs, number and description of each unmetered device; and

(12) Premise type.

If the 814_20 transaction is invalid, ERCOT will respond to the TDSP using the 814_21 transaction within four (4) 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 forty-eight (48) hours counting only hours on Retail Business Days, but not only Business Hours. If the request remains invalid for forty-eight (48) hours, the process will terminate and ERCOT will forward an 814_21 transaction.

ERCOT Protocols

Section 16: Registration and Qualification of Market Participants

August 1, 2009

16 REGISTRATION AND QUALIFICATION OF MARKET PARTICIPANTS

16.1 Registration and Execution of Agreements

ERCOT shall require all Market Participants (MPs) to register and execute the Standard Form Market Participant Agreement and, as applicable, Transmission Congestion Right (TCR) Account Holder Agreement, Reliability Must-Run (RMR) Agreement, and Black Start Agreement.

A Standard Form Market Participant Agreement is provided in Section 22, Agreements, of these Protocols, and shall be posted on the Market Information System (MIS).

All registration procedures and applications necessary to complete registration for any function described herein shall be posted on the MIS. As part of its registration procedures, ERCOT may require:

(1) Reasonable tests of the ability of MPs to communicate with ERCOT or perform as required under these Protocols;

(2) An application fee as determined by the ERCOT Board;

(3) Related agreements for specific purposes, (such as agency designation, meter splitting or network interconnection) that apply only to some MPs; and

(4) 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 20% 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

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

(1) Its Agreement with ERCOT terminated; or

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

(3) Its Customers dropped to a gaining Competitive Retailer (CR) pursuant to Section 15.1.3.

16.2 Registration and Qualification of Qualified Scheduling Entities

16.2.1 Criteria for Qualification as a Qualified Scheduling Entity (QSE)

To become and remain registered and qualified as a QSE, an Entity must:

(1) Execute a Standard Form Market Participant Agreement;

(2) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of performing the functions of a QSE;

(3) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of complying with the requirements of all ERCOT Protocols and guidelines;

(4) Satisfy ERCOT's creditworthiness requirements as set forth in this Section;

(5) Comply with the backup plan requirements outlined in the ERCOT Operating Guides; and

(6) 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.

If a QSE chooses to use EDI transactions to receive Settlement Statements and Invoices, it must participate in and successfully complete testing as described in Protocol Section 23, Texas Test Plan Team Retail Market Testing, prior to commencing operations with ERCOT.

QSEs shall promptly notify ERCOT of any change that materially affects the Entity's ability to satisfy the criteria set forth above. If a QSE fails to inform ERCOT within one (1) day of a material change in the information provided which may affect the reliability or safety of the ERCOT System or the financial security of ERCOT, ERCOT may, after providing notice to each Entity represented by the QSE, refuse to accept schedules from the QSE and take any other action ERCOT deems appropriate to prevent ERCOT and/or Market Participants from bearing potential or actual risk(s), financial or otherwise, arising from such deficiency(ies), and in accordance with these Protocols.

A single Entity acting as a QSE may partition itself into subordinate QSEs ("Subordinate QSEs"), each of which shall be treated as individual QSEs for all purposes except communication, liability, financial security, and financial liability requirements under Section 16.2. Notwithstanding the forgoing, if a single Entity requests to partition itself into more than four (4) 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, that registration shall not be unreasonably delayed. Security and financial liability shall be cumulated for all Subordinate QSEs for the single Entity executing the Standard Form Market Participant Agreement. The Entity executing the Standard Form Market

Participant Agreement will have overall responsibility for all requirements set forth in this Section 16.2, Registration and Qualification of Qualified Scheduling Entities and any liability contained within these Protocols.

Continued qualification as a QSE is contingent upon adherence to all requirements set forth in these Protocols. ERCOT shall suspend a QSE's rights as a Market Participant at such time as ERCOT reasonably determines that the Entity does not satisfy any criterion.

16.2.2 QSE Qualification Requirements

To meet the minimum requirements for qualification by ERCOT a QSE must:

(1) Submit an application for qualification, including any applicable fee;

(2) Execute any required agreements relating to use of the ERCOT network, software and systems;

(3) Designate a representative who shall be responsible for operational communications and who shall have sufficient authority to commit and bind the QSE and Entities it represents;

(4) Maintain a twenty-four (24) hour, seven (7) day per week scheduling center with qualified personnel for the purposes of communicating with ERCOT for scheduling purposes and for deploying the QSE's Ancillary Services in Real Time. These personnel shall be responsible for operational communications and shall have sufficient authority to commit and bind the QSE;

(5) Be financially responsible for payment of settlement charges for those Entities it represents as set forth in Sections 6, 7 and 9 of these Protocols;

(6) Demonstrate a working functional interface with the ERCOT System and all required ERCOT computer systems;

(7) Comply with the backup plan requirements outlined in the ERCOT Operating Guides;

(8) Provide all necessary bank account information and arrange for Fed-Wire System transfers for two-way confirmation; and

(9) Allow ERCOT, upon reasonable notice, to conduct a site visit for verification of provided information.

16.2.3 Application Process for QSE Qualification

To qualify as a QSE, an applicant must submit to ERCOT a completed QSE application and any applicable fee. ERCOT shall post on the ERCOT MIS the QSE application form, all materials that must be provided with the QSE application, the Standard Form Market Participant Agreement, 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 applicant shall promptly notify ERCOT of any material changes affecting a pending application using the appropriate form posted on the MIS. The application must be submitted at least sixty (60) days prior to the proposed date of commencement of service.

16.2.3.1 Notice of Receipt of QSE Application

Within three (3) Business Days after receiving each QSE application, ERCOT shall send the applicant a written confirmation that ERCOT has received the application. ERCOT shall return without review any application that does not include the proper application fee. The remainder of this subsection shall not apply to any application returned for failure to include the proper application fee.

16.2.3.2 Sufficiency of Information Provided by QSE Applicant

Within ten (10) Business Days after receipt of a QSE application, ERCOT shall notify the QSE applicant in writing if the QSE application is incomplete. Within ten (10) Business Days after receipt of a QSE application, if ERCOT does not notify an applicant that the application is incomplete, the application shall be deemed complete as of the date of receipt by ERCOT.

If ERCOT determines that a QSE application is not complete, ERCOT's notification shall explain the deficiencies and stipulate the additional information necessary to make the QSE application complete. The QSE applicant shall then have five (5) Business Days from the receipt of ERCOT's notification, or such longer period as ERCOT may allow, to provide the additional required information. If the QSE applicant responds to the ERCOT notification within the allotted time, then the QSE application shall be deemed complete on the date that ERCOT receives the complete additional information from the applicant.

If the QSE applicant does not respond to ERCOT's notification within the time allotted, ERCOT will reject the application and will notify the applicant according to the procedures below.

16.2.3.3 ERCOT Acceptance or Rejection of QSE Application

ERCOT shall approve or reject each QSE application not more than ten (10) Business Days after the QSE application has been deemed complete in accordance with this subsection. Upon reasonable notice to the QSE applicant, ERCOT may conduct a site visit as part of its evaluation of a QSE application. ERCOT may approve a QSE application on the condition that the QSE applicant agrees to a limitation(s) with respect to the types of transactions that it may conduct with ERCOT.

If ERCOT approves a QSE application, it shall send an approval letter to the QSE applicant, along with a Standard Form Market Participant Agreement and any other required agreements relating to use of the ERCOT network, software and systems for the QSE applicant's signature.

If ERCOT rejects a QSE application, ERCOT shall send the QSE applicant a rejection letter explaining the grounds upon which ERCOT has rejected the QSE application. Appropriate grounds for rejecting a QSE application include:

(1) Required information not provided to ERCOT in the allotted time;

(2) Non-compliance with technical requirements; and/or

(3) Non-compliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

Not later than ten (10) Business Days after receipt of a rejection letter, the QSE applicant may challenge the rejection of its QSE application utilizing the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedures. Regardless of whether or not the QSE applicant challenges the rejection, the applicant may submit a new QSE application and fee and ERCOT shall process the new QSE application in accordance with this subsection.

16.2.4 Remaining Steps for QSE Qualification

Upon receipt of approval notice from ERCOT, an applicant must coordinate or perform the following:

(1) Return the executed Standard Form Market Participant Agreement and other related agreements to ERCOT;

(2) Coordinate with ERCOT and other Entities as necessary, to test all communications necessary to participate in the market in the ERCOT Region;

(3) Submit a Service Filing; and

(4) Demonstrate compliance with security and financial requirements.

16.2.4.1 Qualified Scheduling Entity Service Filing

Not less than fifteen (15) days prior to commencement of any scheduling activities with ERCOT, each QSE must submit a complete Service Filing, including declaration on any subordinate QSEs. ERCOT shall post on the ERCOT MIS the forms and procedures to be used by QSEs to submit Service Filings. The Service Filing shall include:

(1) Proof of credit for ERCOT security amount, as detailed below; the security amount will increase or decrease with the addition or discontinuance of represented Market Participants and/or their respective market activity;

(2) A complete listing of all Entities that the QSE intends to represent. This list will be updated daily up to three (3) days prior to commencement of service by the QSE; and

(3) The date upon which the QSE proposes to commence scheduling activities with ERCOT.

Not more than three (3) Business Days after receiving each Service Filing, ERCOT shall send a written notification to the QSE that it has received the Service Filing. If the Service Filing is not complete, ERCOT shall notify the QSE by telephone, by email, and certified mail with an explanation of the additional information necessary to make the Service Filing complete.

Not more than ten (10) days after a complete Service Filing (either a filing that is initially complete or one that has been supplemented pursuant to the above procedures) is received by ERCOT, ERCOT shall either notify the QSE it may begin scheduling activities upon its proposed commencement date or that ERCOT has reasonably determined that the QSE's Service Filing is insufficient.

Not later than ten (10) Business Days after receipt of a notice of insufficiency, the QSE may challenge the notice of insufficiency utilizing the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedures. Regardless of whether or not the QSE challenges the notice of insufficiency, the QSE may submit a new Service Filing and ERCOT shall process the new Service Filing in accordance with this subsection.

16.2.4.2 Maintaining and Updating QSE Information

Each QSE must timely update information 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, including:

(1) The QSE's addresses;

(2) A list of Affiliates;

(3) Designation of the QSE's Authorized Representatives, Contacts, and User Security Administrator (per the Application for Registration as a QSE) including the addresses (if different), titles, telephone and facsimile numbers, and e-mail addresses for such persons; and

(4) A list of the QSE's officers and directors.

16.2.4.3 Qualified Scheduling Entity Service Termination

If a QSE intends to terminate representation of an LSE or Resource (other than an LSE or Resource serving as its own QSE, in which case this Section does not apply), the QSE will provide Notice to ERCOT and the LSE or Resource no less than twelve (12) Business Days prior to the specified effective termination date ("Termination Date").

Effective at 2400 on the Termination Date specified by the QSE, the QSE will no longer schedule for or represent the terminated LSE or Resource; provided, however, that the QSE is responsible for settlement obligations the QSE has incurred on behalf of the terminated LSE or Resource prior to the termination. The QSE must submit schedules for the Termination Date and update the schedules pursuant to these Protocols for the Operating Day which is the Termination Date. Notwithstanding the foregoing, if, before the Termination Date, the LSE/Resource:

(1) affiliates itself with a new QSE, or

(2) 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 scheduling 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.

Within two (2) 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 should it become an Emergency QSE, as well as the date by which it must post the required collateral.

16.2.5 QSE Financial Security

16.2.5.1 ERCOT Creditworthiness Requirements for QSEs

QSE's must meet ERCOT's creditworthiness requirements and maintain any minimum security amount required, as provided herein and demonstrated in a form acceptable to ERCOT. If the QSE's creditworthiness rating falls below the level required to support the QSE's activity in the market in the ERCOT Region, ERCOT may suspend the QSE's scheduling rights under these Protocols until the QSE submits additional security in accordance with this Section. ERCOT's election not to suspend the QSE's scheduling rights on any particular occasion will not preclude ERCOT from suspending the QSE's scheduling rights on any subsequent occasion.

16.2.5.1.1 Requirements for Establishing Creditworthiness Rating

Minimum short term and long-term debt ratings, minimum average times/interest earning ratio (TIER) and debt service coverage (DSC) ratios, and minimum equity ratios to establish credit worthiness will be adopted by the ERCOT Board of Directors.

A QSE may meet ERCOT's credit requirements, and is not initially required to post security, if the QSE meets one of the following requirements:

(a) Has an Entity Short-Term or Long-Term Debt Rating that meets or exceeds the Minimum Short-Term and Long-Term Debt Ratings adopted by the Board provided that the Entity shall provide (i) quarterly unaudited financial statements not later than sixty (60) days after the close of each of the issuer's fiscal quarters, and (ii) annual audited financial statements not later than one hundred twenty (120) days after the close of each of the issuer's fiscal year; provided however, that if a QSE's financial statements are publicly available electronically and the QSE provides to ERCOT sufficient information to access those financial statements, then the QSE shall be deemed to have met this requirement. ERCOT may extend the period for providing annual audited statements on a case by case basis;

(b) Is an Electric Cooperative, and (i) is a Rural Utilities Service ("RUS") power supply borrower, and (ii) achieves the average TIER and DSC coverage ratios to be approved by the ERCOT Board, as such terms are defined in the Code of Federal Regulations Chapter XVII, and (iii) maintain an equity level approved by the ERCOT Board; and

(c) Is a privately held company without Short Term or Long Term Debt Ratings, and (i) has equity in the amount equal to or greater than the minimum equity level approved by the ERCOT Board for a QSE under this subsection, which may be adjusted by the Board from time to time in its discretion; and, (ii) provides its most recent audited annual, and most recent unaudited interim, financial statements and other information as requested by ERCOT on a basis approved by the ERCOT Board (such as annually, quarterly, or monthly).

16.2.5.1.2 Alternative Means of Satisfying ERCOT Creditworthiness Requirements

If the QSE's activity in the market in the ERCOT Region is greater than the maximum unsecured credit allowed under the standards adopted by the ERCOT Board of Directors ("Unsecured Credit Limit"), the QSE shall submit additional alternative security through one of the following means:

(1) Another Entity that meets or exceeds the Minimum Debt Ratings, as established by the ERCOT Board, may provide a corporate guarantee of the QSE's liability to ERCOT in an amount equal to the QSE's Total Estimated Liability (TEL) or Estimated Aggregate Liability (EAL), whichever is applicable, minus the QSE's Unsecured Credit Limit; provided that the corporate guarantor meets the requirements set forth in Section 16.2.5.1.1. The guarantee must be provided in the form of the ERCOT Board approved standard form guarantee Agreement.

(2) The QSE may provide an irrevocable letter of credit naming ERCOT beneficiary in an amount equal to or greater than the QSE's Total Estimated Liability (TEL) or Estimated Aggregate Liability (EAL), whichever is applicable, minus the QSE's Unsecured Credit Limit. ERCOT may reject the letter of credit if the issuing bank is unacceptable to ERCOT or if the conditions under which ERCOT can draw against the letter of credit are unacceptable to ERCOT. The letter of credit must be provided in the form of the ERCOT Board approved standard form letter of credit.

(3) The QSE may provide a surety bond naming ERCOT beneficiary in an amount equal to or greater than the QSE's Total Estimated Liability (TEL) or Estimated Aggregate Liability (EAL), whichever is applicable, minus the QSE's Unsecured Credit Limit. The surety bond must be executed by a surety acceptable to ERCOT, in compliance with limits established by the ERCOT Board-approved creditworthiness standards, and must be in the form of ERCOT's standard form surety bond agreement.

(4) The QSE may deposit cash in an account designated by ERCOT with the understanding that ERCOT may draw part or all of the cash so deposited to satisfy any overdue payments owed by the QSE to ERCOT. The account may bear interest payable directly to the QSE, provided, however, any such arrangements shall not restrict ERCOT's immediate access to the funds. The cash so deposited shall be in an amount equal to or greater than the QSE's TEL or EAL, whichever applies, minus the QSE's Unsecured Credit Limit. Each QSE agrees that ERCOT has a security interest in all property delivered by the QSE to ERCOT from time to time in order to meet the creditworthiness requirements and that such property secures all amounts owed by the QSE to ERCOT.

16.2.6 Determination and Monitoring of QSE Liability

16.2.6.1 Determination of Total Estimated Liability

ERCOT shall use Total Estimated Liability (TEL) for purposes of Section 16.2.5.1.2, Alternative Means of Satisfying ERCOT Creditworthiness Requirements during the shorter of the first twenty-one (21) days or the first Invoice cycle that the QSE conducts scheduling activities with ERCOT.

16.2.7 Determination of Total Estimated Liability

16.2.7.1 Determination of Initial Total Estimated Liability

ERCOT shall calculate the QSE's initial Total Estimated Liability (TEL), using the following formula:

TEL = DES x BEF x AEP x 40

Where:

TEL = Total Estimated Liability

DES = Estimated Daily Actual Load Schedule (average MWh) plus estimated Daily Actual Generation Schedule initially provided by the QSE in its Service Filing

BEF = Balancing Energy Factor is the greater of:

- (a) Twenty percent (20%) or the estimated actual Load imbalance or Resource imbalance percentage for QSEs that schedule only Load or Generation; or
- (b) The greater of ten percent (10%) or the estimated actual net Load imbalance and Resource imbalance percentage for QSEs that schedule both Load and Generation

AEP = Average Energy Price in the market in the ERCOT Region. AEP is initially based upon on seasonal historic average prices for Balancing Energy

16.2.7.2 Total Estimated Liability Monitoring

During the shorter of the first twenty-one (21) days or the first Invoice cycle of a QSE's operation in the market in the ERCOT Region, ERCOT shall monitor the QSE's actual outstanding liability incurred to date plus the additional forecasted liability that the QSE may incur in a forty (40) day settlement cycle. To the extent that ERCOT reasonably determines that the TEL so calculated is insufficient to provide adequate financial security to the Market Participants in the market in the ERCOT Region, ERCOT may specify a larger TEL than would be produced by the use of the above formula. The QSE shall maintain security in an amount sufficient to satisfy the greater of the initial TEL or the revised TEL, minus the QSE's Unsecured Credit Limit. If at any time an Entity exceeds the twenty percent (20%) BEF (Load side), which is intended to account for the QSE's potential imbalance energy, collateral must be posted to cover the estimated energy use as determined by ERCOT. During the initial twenty-one (21) day period, ERCOT shall monitor the QSEs actual liability to ERCOT and follow the notification procedures in accordance with this Section.

16.2.7.3 Determination of Estimated Aggregate Liability

This subsection applies to all QSEs. After a QSE receives its first Invoice, ERCOT shall monitor daily and calculate, at least weekly, the QSE's Estimated Aggregate Liability (EAL) based on the formula below. Any QSE that is required to post security is responsible, at all times, for maintaining posted security at or above the amount of its EAL, minus the QSE's Unsecured Credit Limit.

EAL = Greater of ADTE or [Highest TEL or ADTE in effect during the previous 60-day period (adjusted for the SAF)] + OUT – $\mathbf{TCR_{ar}}$ + PUL

Where:

EAL =	Estimated Aggregate Liability
TEL =	Total Estimated Liability (as defined in Section 16.2.7 Determination of Total Estimated Liability)
ADTE =	Average daily transaction, extrapolated, which is calculated as (ADT x 40 days x SAF)
ADT =	Average daily transaction, which is calculated from (the sum of the Initial Settlement Statements included in the two most recent Settlement Invoices less the TCR Congestion credits for the same Invoice period to the extent Secured) / the number of Initial Settlement Statements included in the Invoices
OUT =	Outstanding, unpaid transactions, which include outstanding Invoices + estimated unbilled items, to the extent not adequately accommodated in the ADTE calculation above (including but not limited to Balancing Energy, Ancillary Services, resettlements, final, and true-ups). Invoices will not be considered outstanding for purposes of this calculation if prepaid on or before the second (2^{nd}) Business Day following issuance of the Invoice

TCR_{ar} =	TCR auction revenue as described in Section 7.5.4, Allocation Method and Timing for Distributing TCR Auction Revenues, estimated for the sixty (60) day forward period
SAF =	Seasonal Adjustment Factor, which compares size of overall market settlement from statement to statement, and is used to more precisely forecast the liability in the period for which settlement data is not yet available. ERCOT shall set this factor equal to one (1)
PUL =	Potential uplift, to the extent and in the proportion that a QSE represents Entities to which an uplift of a short payment will be made pursuant to Section 9.4.4, Partial Payments, item (6). The sum of: (1) Amounts expected to be uplifted within one year of the date of the calculation; and (2) Twenty-five percent (25%) [or such other percentage based on available statistics regarding default of reorganized Entities of any short payment amounts being repaid under a payment plan ordered by a bankruptcy court for a defaulting QSE] of amounts due more than one year from the date of the calculation
Secured =	The owner of the TCR credit has granted ERCOT a first priority security interest in receivables generated under or in connection with the TCR Account Holder Agreement to secure any and all obligations arising under: (i) the Standard Form Market Participant Agreement, (ii) any agreement identified in Section 16.1 and/or (iii) these Protocols.

To the extent that ERCOT, using commercially reasonable measures, determines that the EAL so calculated does not adequately match the financial risk to the MPs in the market in the ERCOT Region**,** ERCOT may specify a larger or smaller EAL than would be produced by the use of the above formula. ERCOT will, to the extent practical, exchange with the QSE that information utilized in determining credit requirements. ERCOT will provide written notification to the QSE of the basis for ERCOT's assessment of the QSE's financial risk.

16.2.7.4 Determination of Aggregate Net Load Imbalance Liability and Net Resource Imbalance Liability (NLRI)

This subsection applies to all QSEs. For any Invoice periods that have not been invoiced in which the sum of:

(1) The percentage by which a QSE's total estimated Load (MWh) differs from its scheduled Load (MWh); and

(2) The percentage by which a QSE's total estimated Resource (MWh) differs from its scheduled Resource (MWh)

exceeds twenty percent (20%), ERCOT will monitor daily and calculate, at least weekly, an aggregate incremental Net Load Imbalance Liability and Net Resource Imbalance Liability (NLRI), based on the formula below. Any QSE required to post security is responsible, at all times, for maintaining posted security at or above the amount of its EAL, plus its aggregate incremental NLRI minus its Unsecured Credit Limit.

$$\textbf{NLRIq} = \textbf{SUM(NLRIqi)}$$

$$\textbf{NLRIqi} = \textbf{SUM(NLRIqiz)}$$

$$\textbf{NLRIqiz} = (\textbf{LIqiz} + \textbf{RRIqiz})$$

$$\mathbf{LI_{qiz}} = -1 * (\mathbf{SL_{qiz}} - \mathbf{EL_{qiz}}) * \mathbf{MCPE_{iz}} * \mathbf{PM}$$

$$\mathbf{RRI_{qiz}} = (\mathbf{SG_{qiz}} - \mathbf{EG_{qiz}}) * \mathbf{MCPE_{iz}} * \mathbf{PM}$$

Where:

i	interval being calculated
z	zone being settled
LI_{qiz}	Load Imbalance ($) per interval per zone per QSE
SL_{qiz}	Scheduled Load (MWh) per interval per zone per QSE
EL_{qiz}	Estimated Load (MWh) per interval per zone per QSE,
RRI_{qiz}	Relaxed Resource Imbalance ($) per interval per zone per QSE
SG_{qiz}	Scheduled Generation (MWh) per interval per zone per QSE
EG_{qiz}	Estimated Generation (MWh) per interval per zone per QSE,
$MCPE_{iz}$	Market Clearing Price of Energy ($/MWh) per interval per zone
PM	Price Multiplier (150% for periods projected forward, 100% for other periods)
NLRI	Net Load Imbalance Liability and Net Resource Imbalance Liability

1. Load Imbalance for Invoice periods that are completed but for which ERCOT has not issued an Invoice, is calculated as the higher of: (a) ERCOT’s estimate of the QSE’s Load Imbalance for the period or (b) the QSE’s estimate of Load Imbalance for the period.

2. Load Imbalance for an Invoice period not yet completed, is calculated as the higher of: (a) ERCOT’s estimate of the QSE’s Load Imbalance for the most recent seven (7) day period, or (b) the QSE’s forecast of Load Imbalance for the next seven (7) day period.

3. ERCOT shall use actual Resource Imbalance for Invoice periods that are completed but for which ERCOT has not issued an Invoice. For periods in which actual Resource Imbalance is not available, and for Invoice periods that are completed but for which ERCOT has not issued an Invoice, Resource Imbalance is calculated as the higher of: (a) ERCOT’s estimate of the QSE’s Resource Imbalance for the period, including both scheduled and unscheduled Balancing Energy Service, or (b) the QSE’s estimated Resource Imbalance for the period.

4. ERCOT shall use actual Resource Imbalance for an Invoice period not yet completed. For periods in which actual Resource Imbalance is not available, and for an Invoice period not yet completed, Resource Imbalance is calculated as the higher of: (a) ERCOT’s estimate of the QSE’s Resource Imbalance, including both scheduled and unscheduled Balancing Energy Service, for the most recent seven (7) day period, or (b) the QSE’s forecast of Resource Imbalance for the next seven (7) day period.

5. ERCOT will review the price per MWh and multiplier at least quarterly to ensure that no less than ninety-five percent (95%) of the price volatility for a one (1) year period is captured in the calculation. Changes to the PM factor will be reviewed and approved by the Finance and Audit Committee. ERCOT will provide notice to Market Participants of any change at least fourteen (14) days prior to the effective date along with the analysis supporting the change.

To the extent that ERCOT, using commercially reasonable measures, determines that the NLRI as calculated above does not adequately match the financial risk to Market Participants, ERCOT may specify a larger or smaller NLRI than that produced by using the above-referenced formula. ERCOT will, to the extent practical, exchange with the QSE the information ERCOT used in determining those credit requirements. ERCOT will provide written notification to the QSE of the basis for ERCOT's assessment of the QSE's financial risk and the applicable credit requirements.

16.2.8 Monitoring of Creditworthiness by ERCOT

ERCOT shall monitor the creditworthiness and credit exposure of each QSE or its guarantor, if any. To enable ERCOT to monitor creditworthiness, each QSE shall provide to ERCOT:

(1) 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 no later than sixty (60) days (ninety (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; and

(2) Its own or its guarantor's annual audited financial statements no later than one hundred twenty (120) days after the close of each of the issuer's fiscal year;

Provided, however, that if a QSE's or its guarantor's financial statements are publicly available electronically and the QSE provides to ERCOT sufficient information to access those financial statements, then the QSE shall be deemed to have met this requirement. ERCOT may extend the period for providing interim unaudited or annual audited statements on a case-by-case basis.

With respect to a QSE that meets ERCOT creditworthiness requirements pursuant to Section 16.2.5.1.1, Requirements for Establishing Creditworthiness Rating, for any portion of its creditworthiness requirement, such QSE shall inform ERCOT within three (3) Business Days if it has experienced a material change that might reduce the QSE's Unsecured Credit Limit and ERCOT may then require that QSE to meet one of the credit requirements of Section 16.2.5.1.2, Alternative Means of Satisfying ERCOT Creditworthiness Requirements. If the QSE fails to promptly satisfy ERCOT creditworthiness requirements, ERCOT may take remedial action as set forth in these Protocols and provide notice thereof to each Entity represented by the QSE.

With respect to a QSE meeting creditworthiness requirements using an alternative means provided in Section 16.2.5.1.2 for any portion of its creditworthiness requirement, that QSE is responsible, at all times, for maintaining security in an amount at or above its TEL, EAL and NLRI, as applicable, minus the QSE's Unsecured Credit Limit. ERCOT shall promptly notify each QSE of changes to its TEL, EAL and NLRI and allow the QSE time, as set forth in paragraph (1) below, to provide additional security, if necessary, to maintain compliance with Section 16.2.5, QSE Financial Security. If a QSE fails to provide additional security within the time allowed by ERCOT, ERCOT may take remedial action as set forth in these Protocols and provide Notice thereof to each Entity represented by the QSE.

ERCOT shall notify a QSE's Authorized Representative(s) and credit contact when the QSE's EAL reaches ninety percent (90%) of its posted security. ERCOT shall electronically issue a warning advising the QSE that it should consider increasing the amount of security posted with ERCOT. However, ERCOT's failure to issue that warning does not prevent it from exercising any of its other rights under this Section 16, Registration and Qualification of Market Participants. If the QSE does not provide additional security by 1500 (*i.e.*, 3:00 pm) on the second Bank Business Day from the date on which ERCOT provided Notification, then ERCOT may notify the Entities the QSE represents of the QSE's potential suspension.

A QSE's scheduling privilege may be suspended when the sum of its TEL, EAL and NLRI equals or exceeds one hundred percent (100%) of its posted security. The QSE is responsible, at all times, for managing its TEL, EAL and NLRI or posting additional security in order to avoid reaching its credit limit. Any failure by ERCOT to issue a Notification as set forth in this subsection shall not relieve the QSE of the obligation to maintain security in an amount equal to or greater than its TEL, EAL and NLRI. To the extent that a QSE fails to maintain security in an amount equal to or greater than its TEL, EAL, and NLRI, ERCOT shall take the following actions:

(1) ERCOT shall promptly notify the QSE, on a Business Day, of the amount by which the QSE must increase its security and allow the QSE: (a) until 1500 on the second Bank Business Day from the date on which ERCOT delivered Notification to increase the QSE's security if ERCOT delivered its Notice before 1500 on a Business Day, or (b) until 1700 on the second Bank Business Day from the date on which ERCOT delivered Notification to increase the QSE's security if ERCOT delivered its Notice after 1500 but prior to 1700 on a Business Day. ERCOT shall notify the QSE's Authorized Representative(s) and credit contact if it has not received the required security by 1530 on the day on which the security was due; however, failure to notify the QSE's representatives or contacts that ERCOT did not receive the required security does not prevent ERCOT from exercising any of its other rights under this Section 16.

(2) ERCOT: (a) may require the QSE to self-arrange all of its Ancillary Service Obligations and (b) shall not permit the QSE to bid for Ancillary Services until it has posted the additional security.

(3) At the same time as it notifies the QSE, ERCOT may promptly notify each LSE and Resource represented by the QSE that it may have to designate a new QSE(s) if its QSE fails to increase its security.

(4) If the QSE posts the additional security by the deadline in paragraph (1) above, then ERCOT may notify each LSE and Resource represented by the QSE of that fact and permit the QSE to resume procuring Ancillary Services through ERCOT to meet the QSE's Ancillary Service Obligations.

(5) If the QSE fails to post the additional security by the deadline in paragraph (1) above, ERCOT may suspend the QSE's right to schedule and shall notify the affected LSE(s) and Resource Entity(ies) that the QSE has failed to post the required security. In the event that ERCOT suspends some or all of a QSE's rights, the affected Resource Entity(ies) and LSE(s) shall meet the requirements in Section 16.2.13.1, Designation as an Emergency QSE or Virtual QSE.

(6) Notwithstanding any of the foregoing, upon ERCOT's Notification to a QSE that the sum of its TEL, EAL and NLRI equals or exceeds one hundred percent (100%) of its posted security, until the QSE posts the required collateral, ERCOT shall not make payments to that QSE up to the amount of the additional required collateral. The payments that ERCOT will not make to that QSE include TCR Revenues, TCR Credits, reimbursements for short payments and any other reimbursements or credits under any other agreement. ERCOT may retain all such amounts until the QSE has fully complied with its security and/or collateral posting obligations under the Standard Form Market Participant Agreement, other agreements, and/or these Protocols.

16.2.9 Payment Breach and Late Payments by Market Participants

Each Market Participant must ensure that amounts due to ERCOT, or its designee, if applicable, by such Market Participant and, if the Market Participant is a QSE, any Subordinate QSEs it has designated, are submitted in full to ERCOT on a timely basis. Each Subordinate QSE will receive a separate Invoice. Netting of the amounts due by Subordinate QSEs is not allowed. The amount due on the separate Invoices for each Subordinate QSE must be submitted by the close of Bank Business Day of the due date set forth on the Invoice (or, if the due date is not a Bank Business Day, on the next day that is a Bank Business Day). If a Subordinate QSE does not submit the full amount due by close of Bank Business Day of the due date, ERCOT shall deduct the amount due by that Subordinate QSE from the Market Participant and/or any other Subordinate QSE of that Market Participant to the extent of the amount due and not paid by the late paying Subordinate QSE before calculating short payments to other ERCOT Market Participants.

The failure of a Market Participant to pay when due any payment or collateral obligation owed to ERCOT or its designee, if applicable, under the Standard Form Market Participant Agreement, any agreement identified in these Protocols, or otherwise shall constitute an event of "Payment Breach." Additionally, any Payment Breach by a Market Participant will constitute a default under any and all other agreements between ERCOT and the Market Participant. In the event of a Payment Breach, ERCOT will immediately contact the Authorized Representative(s) and credit contact of the Market Participant telephonically and will make appropriate written notices, as described below, and demand payment of the past due amount. Upon a Payment Breach, ERCOT may impose the below-listed remedies for Payment Breach ("Breach Remedies"), as set forth in Section 16.2.9.1, ERCOT's Remedies, in addition to any other rights or remedies it has under the Standard Form Market Participant Agreement, other agreements, the Protocols or the common law.

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If a Market Participant makes a payment or any portion of a payment or a collateral call to ERCOT after the due date and time, such payment shall constitute a “Late Payment.” If ERCOT receives a Late Payment which fully pays the Market Participant’s payment or collateral obligation to ERCOT within two (2) Bank Business Days of the due date, ERCOT will waive the Payment Breach, except for ERCOT’s Remedies for Late Payments, as set forth in Section 16.2.9.2, ERCOT’s Remedies for Late Payments. Even if ERCOT chooses to not immediately impose Default Remedies against a Market Participant because the Market Participant has fully paid its obligation within two (2) Bank Business Days, ERCOT shall track the number of Late Payments received from each Market Participant in any rolling twelve (12) month period, for purposes of imposing the Late Payment Remedies set forth below in Section 16.2.9.2.

16.2.9.1 ERCOT’s Remedies

In addition to all other remedies that ERCOT has, pursuant to the Standard Form Market Participant Agreement, other agreements, these Protocols or the common law, for Payment Breaches and other defaults by a Market Participant, ERCOT has the following additional remedies:

16.2.9.1.1 No Payments by ERCOT to Market Participant

ERCOT shall not make any payment to a Market Participant unless or until the Market Participant cures the Payment Breach. The payments ERCOT will not make to a Market Participant in breach of any agreement with ERCOT include TCR Revenues, TCR Credits, reimbursements for short payments, and any other reimbursements or credits under any other agreement. ERCOT shall retain all such amounts until the Market Participant has fully paid all amounts owed to ERCOT under Standard Form Market Participant Agreement, other agreements and/or these Protocols. If the Market Participant should fail to pay the full amount due, ERCOT may apply all funds it withheld toward the payment of the delinquent amount.

16.2.9.1.2 ERCOT May Draw On, Hold or Distribute Funds

Upon a Payment Breach, ERCOT, at its option and its sole discretion, without notice to the Market Participant, may immediately, or at any time, draw on, hold or distribute to Market Participants any 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 the excess funds as security.

16.2.9.1.3 Aggregate Amount Owed by Market Participant Immediately Due

ERCOT shall aggregate all amounts due it by the Market Participant under the Standard Form Market Participant Agreement, any other agreement with ERCOT or the 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 sole discretion, shall become immediately due and payable without further notice and demand for payment, which notice and demand are expressly waived by the defaulting Market Participant.

16.2.9.1.4 Revocation of a Market Participant's Rights and Termination of Agreements

ERCOT may revoke one or more of a Market Participant's rights to conduct activities under these Protocols. ERCOT may also terminate a Standard Form Market Participant Agreement with ERCOT and may terminate any and all other agreements between that Market Participant and ERCOT.

If ERCOT revokes a Market Participant's rights or terminates a Standard Form Market Participant Agreement, then the provisions of Section 16.2.12, Suspended Qualified Scheduling Entity – Notification to LSEs and Resource Entities Represented, and Section 16.2.13.1, Designation as an Emergency QSE or Virtual QSE apply.

If the breaching Market Participant is an LSE (whether or not the breach occurred pursuant to the Market Participant's activities as an LSE), then:

(1) Within twenty-four (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

(2) On revocation of some or all of the Market Participant's rights or termination of its Agreements and upon notice to the Market Participant and the PUCT, ERCOT shall initiate a mass transition of the LSE's ESI IDs pursuant to Section 15.1.3, Mass Transition, without the necessity of obtaining any order from or other action by the PUCT.

After revocation of its rights or termination of its agreements with ERCOT, the Market Participant will remain liable for all charges or costs associated with any continued activity related to the Market Participant's relationship with ERCOT and any costs and expenses arising from the consequences of such termination or revocation.

16.2.9.2 ERCOT's Remedies for Late Payments

If a Market Participant makes any Late Payments, and even if ERCOT does not immediately implement the above remedies for any Payment Default, ERCOT is hereby empowered to, and ERCOT shall, take action for Late Payments as follows:

16.2.9.2.1 First Late Payment in any rolling twelve (12) month period

For the first Late Payment in any rolling twelve (12) month period, ERCOT shall review the circumstances and reason for the Late Payment, and shall, at its sole discretion, determine whether it should take Level I Enforcement action against the Market Participant. ERCOT will send a Notification to the Authorized Representatives and credit contact of the Market Participant advising the Market Participant whether or not ERCOT will take Level I

Enforcement action and advising the Market Participant of the action required under Level I Enforcement, if applicable.

16.2.9.2.2 Second Late Payment in any rolling twelve (12) month period

For the second Late Payment in any rolling twelve (12) month period, ERCOT shall review the circumstances and reason for the Late Payment, and may take action as follows:

(1) If ERCOT did not take Level I Enforcement action in the case of the First Late Payment, ERCOT may take Level I Enforcement action related to this Late Payment.

(2) If ERCOT did take Level I Enforcement action in the case of the First Late Payment, ERCOT may take Level II Enforcement action related to this Late Payment.

(3) ERCOT shall send Notification to the Authorized Representatives and credit contact of the Market Participant; advising the Market Participant of the action required under Level I or Level II Enforcement.

16.2.9.2.3 Third Late Payment in any rolling twelve (12) month period

For the third Late Payment in any rolling twelve (12) month period, ERCOT shall review the circumstances and reason for the Late Payment, and may take action as follows:

(1) If ERCOT did not take Level II Enforcement action in the case of the Second Late Payment, ERCOT may take Level II Enforcement action related to this Late Payment.

(2) If ERCOT did take Level II Enforcement action in the case of the Second Late Payment, ERCOT may take Level III Enforcement action related to this Late Payment.

(3) ERCOT shall send Notification to the Authorized Representatives and credit contact of the Market Participant advising the Market Participant of the action required under Level II or Level III Enforcement.

16.2.9.2.4 Fourth and all subsequent Late Payments in any rolling twelve (12) month period

For the fourth and all subsequent Late Payments in any rolling twelve (12) month period:

(1) ERCOT may take Level III Enforcement action related to this Late Payment.

(2) ERCOT shall send Notification to the Authorized Representatives and credit contact of the Market Participant advising the Market Participant of the action required under Level III Enforcement.

16.2.9.2.5 Level I Enforcement

Under Level I Enforcement, the Market Participant shall comply with one of the following requirements; whichever is appropriate as determined by ERCOT at its sole discretion:

(1) If the Market Participant has not been required to provide security, the Market Participant shall now be required to provide security within two (2) Bank Business Days, in an amount at or above one hundred ten percent (110%) of:

(a) The amount of the Market Participant's Total Estimated Liability (TEL) or Estimated Aggregate Liability (EAL)) less the Unsecured Credit Limit; or

(b) Any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

(2) If the Market Participant already provided security, it shall increase its posted security, within two (2) Bank Business Days, to an amount at or above one hundred ten percent (110%) of:

(a) Its TEL or EAL, less its Unsecured Credit Limit; or,

(b) Any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

16.2.9.2.6 Level II Enforcement

Under Level II Enforcement, the Market Participant shall post, within two (2) Bank Business Days, security in the form of a cash deposit or letter of credit, as chosen by ERCOT at its sole discretion, at one hundred ten percent (110%) of the Market Participant's TEL or EAL, 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, whichever applies.

FAILURE TO COMPLY WITH INCREASED SECURITY REQUIREMENTS UNDER LEVEL I OR LEVEL II ENFORCEMENT MAY RESULT IN SUSPENSION OF THE QSE'S RIGHT TO SCHEDULE IN THE MARKET IN THE ERCOT REGION UNTIL SUCH SECURITY IS ESTABLISHED, AND WILL CONSTITUTE GROUNDS FOR TERMINATION OF THE MARKET PARTICIPANT'S AGREEMENTS WITH ERCOT.

INCREASED SECURITY REQUIREMENTS UNDER THIS SUBSECTION SHALL REMAIN IN EFFECT FOR A MINIMUM OF SIXTY (60) DAYS AND SHALL REMAIN IN EFFECT THEREAFTER UNTIL ERCOT, AT ITS SOLE DISCRETION, DECIDES TO REDUCE SUCH SECURITY REQUIREMENTS.

16.2.9.2.7 Level III Enforcement

ERCOT shall make reasonable efforts to meet with the Authorized Representative(s) and credit contact of the Market Participant to discuss the Late Payment occurrences. ERCOT shall take one or more of the following actions:

(1) Advise the Authorized Representative(s) that a subsequent Late Payment in the rolling twelve (12) month period could result in termination of the Market Participant's right to schedule capacity or energy in the ERCOT Region; or

(2) Take action under Section 16.2.9.1.4, Revocation of a Market Participant's Rights and Termination of Agreements, above.

16.2.10 Release of QSE's Security Requirement

ERCOT may, at it its sole discretion, following the termination of a Standard Form Market Participant Agreement and within thirty (30) days of being satisfied that no sums remain owing, or will become due and payable, by the Market Participant under these Protocols, return or release to the Market Participant, as appropriate, any security provided under this Section.

16.2.11 Posting of Recognized QSE List

ERCOT shall post on the ERCOT MIS and maintain current a list of all recognized QSEs. ERCOT shall include with such posting a cautionary statement that inclusion on such 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.

16.2.12 Suspended Qualified Scheduling Entity – Notification to LSEs and Resource Entities Represented

If a QSE can no longer function as a QSE or if ERCOT suspends the QSE's qualification, ERCOT shall notify the affected LSEs and Resource Entities that the QSE has been suspended and the effective date of such suspension.

If an LSE or Resource Entity represented by the failed or suspended QSE is the same Entity as the failed or suspended QSE, the provisions of Section 16.2.9.1.4, 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.

16.2.13 Emergency Qualified Scheduling Entity

16.2.13.1 Designation as an Emergency QSE or Virtual QSE

(1) 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 this Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

(2) If ERCOT has given notice of an LSE's or Resource Entity's QSE's suspension, that LSE or Resource Entity will be designated as a Virtual QSE for up to two (2) 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, Registration and Qualification of Qualified Scheduling Entities, and operate as Emergency QSE as described below.

(3) If an LSE or Resource Entity meets the creditworthiness requirements, the LSE or Resource Entity may be designated as an Emergency QSE and may, be issued digital certificates and given access to the scheduling capabilities of the MIS as determined by ERCOT.

(4) If an LSE fails to meet the requirements of one of the options set forth in paragraph (1) or (2) above within the requisite timeframe, ERCOT shall, after notice to the LSE and the PUCT, initiate a Mass Transition of the LSE's ESI IDs pursuant to Section 15.1.3, Mass Transition.

(5) If a Resource Entity fails to meet the requirements of one of the options set forth in paragraph (1) or (2) above within the requisite timeframe, ERCOT may allow the Resource Entity additional time, as determined by ERCOT staff, to meet the requirements.

(6) For any Operating Day in which and 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 scheduling 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.

(7) ERCOT shall maintain a referral list of qualified QSEs on the public MIS 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.

16.2.13.2 Scheduling by an Emergency QSE or a Virtual QSE

An Emergency QSE or a Virtual QSE:

(1) May represent only itself and may only submit schedules representing QSE-to-QSE trades and its Obligations; and

(2) If a LSE, may submit schedules for transactions described in item (1) above only to the extent that those transactions are intended to serve the Load of its own ESI IDs; and

(3) If a Resource Entity, may submit Schedules for transactions described in item (1) above only to the extent that those Schedules are wholly provided by the Resource Entity's Resource(s).

16.2.13.3 Requirement to Obtain New QSE or QSE Qualification

Within seven (7) Business Days of receiving designation as an Emergency QSE, an Emergency QSE must either:

(1) Designate a QSE that will represent the LSE or Resource Entity for purposes of scheduling and settlement with ERCOT, or;

(2) Fulfill all QSE registration and qualification requirements.

After completing the requirements in item (2), ERCOT may redesignate the Emergency QSE as a QSE.

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 to the Emergency QSE and the PUCT, initiate a Mass Transition of the LSE's ESI IDs pursuant to Section 15.1.3, Mass Transition.

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.

16.2.14 Acceleration

Upon termination of a Market Participant's rights under any of the agreement(s) between ERCOT and the Market Participant, all sums owed to ERCOT shall immediately be accelerated and be immediately due and owing in full. At such time, ERCOT may immediately draw upon any security or other collateral pledged by the Market Participant and may offset or recoup all amounts due to ERCOT to satisfy such due and owing amounts.

16.3 Registration of Load Serving Entities

Load Serving Entities (LSEs) provide electric service to Customers and Wholesale Customers. LSEs include Non-Opt In Entities, Competitive Retailers (CRs) and Retail Electric Providers (REPs). All LSEs operating in ERCOT, and/or in non-ERCOT portions of the state of Texas in areas where Customer Choice is in effect must register with ERCOT. To become registered as a LSE, an Entity must execute a Standard Form Market Participant Agreement, designate LSE Authorized Representatives, contacts, and User Security Administrator (per the Application for Registration as an LSE), and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Load Serving Entity as described in applicable Sections of these Protocols. Additionally, a REP must demonstrate certification by the Public Utility Commission of Texas (PUCT) Requirements for Competitive Retailer registration.

16.3.1 Registration Process of Load Serving Entities

Any LSE operating in ERCOT, and/or Non-ERCOT portions of the state of Texas in areas where Customer Choice is in effect must file a Load Serving Entity application ("LSE application") as set forth in this subsection. In addition, ERCOT may require that the Entity satisfactorily complete testing of interfaces between the Entity's systems and relevant ERCOT systems. The LSE application shall include any LSE application fee set forth in ERCOT's Service Fee Schedule posted on the MIS.

A LSE operating in the ERCOT Region must designate a QSE for scheduling and settlement with ERCOT.

REPs are required to submit a copy of their final certification from the PUCT as part of the registration process.

All CRs must participate in and successfully complete testing as described in Protocol Section 23, Texas Test Plan Team - Retail Market Testing, prior to commencing operations with ERCOT.

16.3.1.1 Technical and Managerial Resource Requirements

Technical and managerial resource requirements for LSEs include:

(1) Capability to comply with all policies, rules, guidelines, and procedures established by these Protocols, ERCOT or other Independent Organization, if applicable.

(2) Capability to comply with ERCOT's registration requirements or other Independent Organization and its system rules and contract for the purchase of power from Entities registered with or by the ERCOT or Independent Organization and capable of complying with its system rules.

(3) (ERCOT LSEs only) Purchase of capacity and reserves, or other Ancillary Services, as may be required by ERCOT or other Independent Organization to provide adequate electricity to all the applicant's Customers in its area.

16.3.1.2 Designation of a QSE

Each applicant shall designate in its application the QSE that will represent the applicant for purposes of scheduling and settlement with ERCOT. Each applicant shall acknowledge in its application that it bears sole responsibility for selecting and maintaining a commercial relationship with a QSE. The applicant shall include in its application, a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the applicant's scheduling and settlement transactions pursuant to these Protocols.

An LSE may be required to designate a backup QSE as demonstrated in this section.

If an LSE fails to maintain a commercial relationship with a QSE, the LSE may be designated as an Emergency QSE as provided in this Section.

16.3.1.3 Incomplete Applications

Not more than ten (10) Business Days after receipt of each application, ERCOT shall notify the applicant in writing whether the application is complete.

If ERCOT determines that an application is not complete, ERCOT's notification shall explain the reasons therefore and the additional information necessary to make the application complete. The applicant shall then have five (5) Business Days from the receipt of ERCOT's notification, or such longer period as ERCOT may allow, to provide the additional information set forth in ERCOT's notification. If the applicant timely responds to ERCOT's notification, then the application shall be deemed complete on the date that ERCOT receives the applicant's response.

If the applicant does not timely respond to ERCOT's notification, then the application shall be rejected, and ERCOT shall retain any application fee included with the application.

16.3.1.4 Approval of the Application for CRs

ERCOT shall approve or reject each application not more than ten (10) Business Days after the application has been deemed complete in accordance with this subsection. Upon reasonable notice to the applicant, ERCOT may conduct a site visit as part of its evaluation of an application.

If ERCOT approves an application, it shall send an approval letter to the applicant, along with a Standard Form Market Participant Agreement and any required software licensing agreements for the applicant's signature. The CR shall be deemed registered when ERCOT receives back the executed Standard Form Market Participant Agreement.

If ERCOT rejects an application, ERCOT shall send the applicant a rejection letter explaining the grounds upon which ERCOT has rejected the application. Appropriate grounds for rejecting an application include:

(1) Non-compliance with technical requirements; and

(2) Non-compliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

Not later than ten (10) Business Days after receipt of a rejection letter, the applicant may challenge the rejection of its application utilizing the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedures. Regardless of whether or not the applicant challenges the rejection, the applicant may submit a new application and ERCOT shall process the new application in accordance with this subsection.

16.3.2 Requirements for Reporting and for Changing the Terms of an LSE Registration

In order to maintain its registration status, the LSE must keep the registration information up to date, pursuant to the following requirements:

(1) An LSE may change its designation of QSE no more than once in any given three (3) day period. The LSE shall include a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the LSE's scheduling and settlement transactions pursuant to these Protocols.

(2) Each LSE shall notify ERCOT within seven (7) Business Days of any material changes in the information included on its application.

(3) If an LSE's representation by a QSE will terminate or the LSE intends to be represented by a different QSE, the LSE shall submit updated QSE representation information to ERCOT no less than six (6) days prior to the effective date. Within two (2) days of receiving notice, ERCOT will notify all affected parties, including the LSE's current QSE, of the effective date of the change.

16.3.3 LSEs Outside of ERCOT

LSEs operating only outside of the ERCOT Region are not required to designate a QSE.

Any LSE operating only outside of the ERCOT Region but within the state of Texas ("Non-ERCOT LSE") is required to register with ERCOT, but shall not be required to comply with those sections of the Protocols that relate only to operations in the ERCOT Region.

16.4 Registration of ERCOT and Non-ERCOT Transmission and Distribution Service Providers (TDSP)

Any Entity operating as a Transmission and/or Distribution Service Provider (TDSP) within the ERCOT Region, including Municipally Owned Utilities (MOUs) and Electric Cooperatives (ECs), shall register as a TDSP with ERCOT. Any TDSP operating only outside of the ERCOT Region but within the state of Texas ("Non-ERCOT TDSP") shall also register as a TDSP, provided that Non-ERCOT TDSPs shall not be required to comply with sections of the Protocols relating only to operations in the ERCOT Region. To register as a TDSP, an Entity must comply with the backup plan requirements outlined in the ERCOT Operating Guides, designate TDSP Authorized Representatives, contacts, and User Security Administrator (per the Application for Registration as a TDSP), execute a Standard Form Market Participant Agreement and be capable of performing the functions of a TDSP as described in these Protocols.

All TDSPs operating within portions of the state of Texas in areas where Customer Choice is in effect (including opt-in MOUs and Cooperatives) must participate in and successfully complete testing as described in Section 23, Texas Test Plan Team - Retail Market Testing, prior to commencing operations with ERCOT.

16.5 Registration of Generation Resources, Loads Acting as a Resource and Emergency Interruptible Load Service Resources

Every Generation Resource connected to the ERCOT Transmission System, distributed generator over one (1) megawatt (MW), Load acting as a Resource and Emergency Interruptible Load Service (EILS) Resource must register with ERCOT.

Distributed generation is an electrical generating facility located at a Customer's point of delivery (point of common coupling) of ten (10) megawatts (MW) or less and connected at a voltage less than or equal to sixty (60) kilovolts (kV) which may be connected in parallel operation to the utility system.

To register as a Resource Entity, an applicant must submit a Resource Entity application, execute a Standard Form Market Participant Agreement, designate Resource Entity Authorized Representatives, contacts, and User Security Administrator (per the Application for Registration as a Resource Entity), and be capable of performing the functions of a Resource Entity as described in these Protocols.

EILS Resources are not considered Resource Entities. EILS Resources shall register with ERCOT by completing and signing Appendix A, To Supplement to QSE Agreement (*Acknowledgement by EILS Resource Owning or Controlling Entity),* of Section 22(K), Standard Form Emergency Interruptible Load Service (EILS) Agreement.

16.5.1 Responsibilities of the Resource

Each Resource shall be responsible for conducting its operations in accordance with all applicable ERCOT Protocols and guidelines.

16.5.1.1 Waiver for Federal Hydroelectric Facilities

ERCOT may grant a waiver to any federally owned hydroelectric Resource facility, within the ERCOT system, from fulfilling the requirements in Section 16.5 as they pertain to the submission of a Resource application and the execution of a Standard Form Market Participant Agreement. ERCOT may grant such waiver after the federally owned hydroelectric Resource facility provides ERCOT with the following:

(1) All information necessary to meet the Resource registration requirements as provided in Section 16, Registration and Qualification of Market Participants;

(2) The designation of a QSE for the Resource; and

(3) A Load Serving Entity must be assigned to the ESI ID associated with any Load or net Load, if the Resource is net metered, which will be connected to the ERCOT System. Such Load, if retail Load, shall be subject to all applicable rules and procedures, including rules concerning disconnection and POLR service, applicable to retail points of delivery.

16.5.1.2 Waiver for Block Load Transfer Resources

ERCOT may grant a waiver to any BLT Resource from fulfilling the requirements in Section 16.5, Registration of Generation Resources and Loads Acting as a Resource, as they pertain to the submission of a Resource application and the execution of a Standard Form Market Participant Agreement. ERCOT may grant such waiver after the BLT Resource provides ERCOT with the following:

(1) All applicable information necessary to meet the Resource registration requirements as provided in Section 16; and

(2) The designation of a QSE for the BLT Resource.

16.5.2 Registration Process for a Resource

To register as a Resource, an Entity must:

(1) Designate and maintain a relationship with a QSE or QSEs as specified in the Protocols,

(2) Demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Resource,

(3) Demonstrate that it is capable of complying with the requirements of all ERCOT Protocols and guidelines.

16.5.2.1 Technical and Managerial Resource Requirements

Technical and managerial resource requirements for Resources include:

(1) Capability to comply with all policies, rules, guidelines, and procedures established by these Protocols, ERCOT or other Independent Organization, if applicable.

(2) Capability to comply with ERCOT's registration requirements or other Independent Organization and its system rules and contract for the purchase of power from Entities registered with or by the ERCOT or Independent Organization and capable of complying with its system rules.

16.5.2.2 Designation of a QSE

Each applicant shall designate in its Resource application the QSE that will represent the applicant for purposes of scheduling and settlement with ERCOT. Each applicant shall acknowledge in its application that it bears sole responsibility for selecting and maintaining a commercial relationship with a QSE. The applicant shall include in its application, a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the applicant's scheduling and settlement transactions pursuant to these Protocols.

16.5.2.3 Incomplete Resource Applications

Not more than ten (10) Business Days after receipt of each application, ERCOT shall notify the applicant in writing whether the application is complete.

If ERCOT determines that an application is not complete, ERCOT's notification shall explain the reasons therefore and the additional information necessary to make the application complete. The applicant shall then have five (5) Business Days from the receipt of ERCOT's notification, or such longer period as ERCOT may allow, to provide the additional information set forth in ERCOT's notification. If the applicant timely responds to ERCOT's notification, then the application shall be deemed complete on the date that ERCOT receives the applicant's response.

If the applicant does not timely respond to ERCOT's notification, then the application shall be rejected, and ERCOT shall retain any application fee included with the application.

16.5.2.4 Approval of the Resource Application

ERCOT shall approve or reject each application not more than ten (10) Business Days after the application has been deemed complete in accordance with this subsection. Upon reasonable notice to the applicant, ERCOT may conduct a site visit as part of its evaluation of an application.

If ERCOT approves an application, it shall send an approval letter to the applicant, along with an agreement and any required software licensing agreements for the applicant's signature. The Resource shall be deemed registered when ERCOT receives back the executed agreement.

If ERCOT rejects an application, ERCOT shall send the applicant a rejection letter explaining the grounds upon which ERCOT has rejected the application. Appropriate grounds for rejecting an application include:

(1) Non-compliance with technical requirements; and

(2) Non-compliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

Not later than ten (10) Business Days after receipt of a rejection letter, the applicant may challenge the rejection of its application utilizing the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedures. Regardless of whether or not the applicant challenges the rejection, the applicant may submit a new application and ERCOT shall process the new application in accordance with this subsection.

16.5.3 Requirements for Reporting and for Changing the Terms of a Resource Registration

In order to maintain its registration status, the Resource must keep the registration information up to date, pursuant to the following requirements:

(1) A Resource may change its designation of QSE no more than once in any given three (3) day period.

(2) The Resource shall include a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the Resource's scheduling and settlement transactions pursuant to these Protocols.

(3) If a Resource's representation by a QSE will terminate or the Resource intends to be represented by a different QSE, the Resource shall submit updated QSE representation information to ERCOT. Within two (2) days of receiving notice, ERCOT will notify all affected parties, including the Resource's current QSE, of the effective date of the change.

(4) If a Resource receives notification from its QSE or from ERCOT that its current QSE intends to terminate representation, then the Resource must submit updated QSE representation information to ERCOT in accordance with this Section. ERCOT's systems will reflect the relationship between the Resource and its new QSE upon successful completion of all necessary testing, e.g., telemetry, SCADA and RTU (Remote Terminal Unit) points. ERCOT will notify all affected parties (current QSE, new QSE, and affected Resource) of the effective date.

(5) If a Resource Entity has a Switchable Resource with a requirement in the grid outside the ERCOT Region for the months of July through August (peak period), it shall report to ERCOT in writing on June 8, 2005 and then annually by April 1, the days that the identified capacity will not be available to the ERCOT System during the peak period.

Each Resource shall notify ERCOT within seven (7) Business Days of any material changes in the information included on its application, except as specified in Section 16.5.3(5).

16.6 Registration of Municipally Owned Utilities and Electric Cooperatives in the ERCOT Region

A Municipally-Owned Utility and Electric Cooperative (MOU/Coop) is required to register with ERCOT and sign the Standard Form Market Participant Agreement and indicate the applicable functions it performs in the ERCOT Region, regardless of whether planning to be a Non-Opt In or a Competitive Retailer.

Municipally Owned Utilities and Cooperatives in the ERCOT Region, must notify ERCOT six (6) months prior to opting into retail competition, and register with ERCOT as a Competitive Retailer.

Every MOU/Coop must designate a QSE to schedule and settle with ERCOT on its behalf.

All non-opt-in utilities shall have ESI-IDs assigned to their wholesale points of delivery as specified in these Protocols. The ESI-IDs must be assigned to an LSE.

16.7 Registration of REC Account Holders

Any Entity wishing to participate in the REC Trading Program shall register with ERCOT and execute a Standard Form Market Participant Agreement prior to participating in such program.

16.8 Registration of TCR Account Holders

Any Entity wishing to participate in the auction and registration of TCRs shall register with ERCOT and execute a TCR Account Holder Agreement prior to any participation in such program. In order to participate in the TCR auction, TCR bidders must meet the financial requirements approved by the ERCOT Board.

16.8.1 Qualification of a TCR Account Holder

16.8.1.1 Criteria for Qualification as a TCR Account Holder

To be qualified as a TCR Account Holder, an Entity must:

(1) Execute a TCR Account Holder Agreement (the standard form is provided in Section 22 and posted on the MIS);

(2) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of performing the functions of a TCR Account Holder; and

(3) Satisfy ERCOT's creditworthiness requirements as set forth in this Section, if applying to bid in ERCOT's TCR Auction.

TCR Account Holders shall promptly notify ERCOT of any change that materially affects the Entity's ability to satisfy the criteria set forth above. If a TCR Account Holder fails to inform ERCOT within one (1) calendar day of a material change in the information provided which may affect the reliability or safety of the ERCOT System or the financial security of ERCOT, ERCOT may refuse to accept bids or TCR transfers from the TCR Account Holder and take any other action deemed appropriate.

Continued qualification, as a TCR Account Holder is contingent upon adherence to all requirements set forth in these Protocols. ERCOT shall suspend the TCR Account Holder's rights at such time as ERCOT reasonably determines that the Entity does not satisfy the criteria set forth above.

Unbundled TDSPs may not be TCR Account Holders.

16.8.1.2 TCR Account Holder Qualification Requirements

To meet the minimum requirements for qualification by ERCOT, a TCR Account Holder must:

(1) Submit an application for qualification, including any applicable fee.

(2) Execute any required agreements relating to use of the ERCOT network, software and systems.

(3) Be financially responsible for payment of any applicable settlement charges as set forth in Sections 6, 7 and 9 of these Protocols.

(4) Demonstrate a working functional interface with any required applicable ERCOT systems as defined by these Protocols; and

(5) Provide all necessary bank account information and arrange for Fed-Wire System transfers for two-way confirmation.

16.8.1.3 Application Process for TCR Account Holder Qualification

To qualify as a TCR Account Holder, a TCR Account Holder applicant must submit to ERCOT a TCR Account Holder application, TCR Account Holder credit application, if applicable, and any applicable fee. ERCOT shall post on the ERCOT MIS the form in which the TCR Account Holder application must be submitted, all materials that must be provided with the TCR Account Holder application, the TCR Account Holder Agreement, and the fee schedule, if any, applicable to TCR Account Holder applications and TCR Account Holder credit application. The TCR Account Holder application shall be attested to by a duly authorized officer or agent of the TCR Account Holder applicant. The TCR Account Holder applicant shall promptly notify ERCOT of any material changes affecting a pending TCR Account Holder application using the appropriate form posted on the ERCOT MIS. All application forms and fees must be submitted at least fifteen days (15) prior to the Participant's proposed date of participation in the TCR auction process.

16.8.1.3.1 Notice of Receipt of TCR Account Holder Application

Within five (5) Business Days after receiving each TCR Account Holder application and TCR Account Holder credit application, ERCOT shall send the TCR Account Holder applicant a written confirmation that ERCOT has received the TCR Account Holder application and TCR Account Holder credit application. ERCOT shall return without review any TCR Account Holder application that does not include the proper application fee. The remainder of this subsection shall not apply to any TCR Account Holder application returned for failure to include the proper application fee.

16.8.1.3.2 Sufficiency of Information Provided by TCR Account Holder Applicant

Within five (5) days after receipt of a TCR Account Holder application and TCR Account Holder credit application, ERCOT shall notify the TCR Account Holder applicant in writing if the TCR Account Holder application is incomplete. Within five (5) days after receipt of a TCR Account Holder application, if ERCOT does not notify an applicant that the application is incomplete, the application shall be deemed complete as of the date of receipt by ERCOT.

If ERCOT determines that a TCR Account Holder application and TCR Account Holder credit application is not complete, ERCOT's notification shall explain the deficiencies and stipulate the additional information necessary to make the TCR Account Holder application complete. The TCR Account Holder applicant shall then have five (5) Business Days from the receipt of ERCOT's notification, or such longer period as ERCOT may allow, to provide the additional required information. If the TCR Account Holder applicant responds to the ERCOT notification within the allotted time, then the TCR Account Holder application shall be deemed complete on the date that ERCOT receives the complete additional information from the applicant.

If the TCR Account Holder applicant does not respond to ERCOT's notification within the time allotted, ERCOT will reject the application and will notify the applicant according to the procedures below.

16.8.1.3.3 ERCOT Acceptance or Rejection of TCR Account Holder Application

ERCOT shall approve or reject each TCR Account Holder application and TCR Account Holder credit application not more than ten (10) days after the TCR Account Holder application and TCR Account Holder credit application has been deemed complete in accordance with this subsection.

If ERCOT approves a TCR Account Holder application, it shall send an approval letter to the TCR Account Holder applicant, along with a TCR Account Holder Agreement and any other required agreements relating to use of the ERCOT network, software and systems for the TCR Account Holder applicant's signature.

If ERCOT rejects a TCR Account Holder application, ERCOT shall send the TCR Account Holder applicant a rejection letter explaining the grounds upon which ERCOT has rejected the TCR Account Holder application. Appropriate grounds for rejecting a TCR Account Holder application include:

(1) Required information not provided to ERCOT in the allotted time;

(2) Non-compliance with technical requirements; and/or

(3) Non-compliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

Not later than ten (10) Business Days after receipt of a rejection letter, the TCR Account Holder applicant may challenge the rejection of its TCR Account Holder application utilizing the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedures. Regardless of whether or not the TCR Account Holder applicant challenges the rejection, the applicant may submit a new TCR Account Holder application and fee, if applicable. ERCOT shall process the new TCR Account Holder application in accordance with this subsection.

16.8.1.4 Remaining Steps for TCR Account Holder Qualification

After approval by ERCOT of an applicant's application and Credit Application, an applicant must coordinate or perform the following:

(1) Return the executed TCR Account Holder Agreement and other related agreements to ERCOT;

(2) Coordinate with ERCOT and other Entities as necessary, to test all communications necessary to participate in the ERCOT TCR market; and

(3) Complete compliance with security requirements.

16.8.1.4.1 TCR Account Holder Proof of Credit

In accordance with the application procedures set forth in Section 16.8.1.3, each TCR Account Holder must submit proof of credit for its estimated and actual TCR Account Holder auction liability amount.

16.8.1.5 TCR Account Holder Financial Security

16.8.1.5.1 ERCOT Creditworthiness Requirements for TCR Account Holders

TCR Account Holders must meet ERCOT's creditworthiness requirements and maintain any minimum security amount required, as provided herein and demonstrated in a form acceptable to ERCOT. If a TCR Account Holder's creditworthiness rating falls below the level established by the ERCOT Board described below, ERCOT will suspend the TCR Account Holder's TCR bidding activities under these Protocols until the TCR Account Holder submits another form of security in accordance with this Section.

16.8.1.5.2 Requirements for Establishing Creditworthiness Rating

Minimum Long-Term or Issuer Rating, minimum equity level, minimum average times/interest earning ratio (TIER) and debt service coverage (DSC) ratios, and minimum equity ratios to establish creditworthiness have been adopted by the ERCOT Board of Directors.

A TCR Account Holder may meet ERCOT's credit requirements, and shall not initially be required to post security, if the TCR Account Holder meets one of the following requirements:

(a) Has an Entity Long-Term or Issuer Rating and equity level that meets or exceeds the Minimum Long-Term or Issuer Rating adopted by the Board;

(b) Is an Electric Cooperative, and (i) is a Rural Utilities Service ("RUS") power supply borrower, and (ii) achieves the average TIER and DSC coverage ratios approved by the ERCOT Board, as such terms are defined in the Code of Federal Regulations Chapter XVII, (iii) achieves the average Equity to Assets ratio as approved by the ERCOT Board, and (iv) maintains an equity level approved by the ERCOT Board;

(c) Is a privately held company without a Long Term or Issuer Rating, and (i) has equity in the amount equal to or greater than the minimum equity level approved by the ERCOT Board for a TCR Account Holder under this subsection, which amount may be adjusted by the Board from time to time in its discretion; (ii) achieves the minimum current, Debt to Capitalization, and EBITDA to Interest & CMLTD rations as approved by the ERCOT Board and, (iii) provides its most recent audited and/or unaudited financial statements and other information as requested by ERCOT on a basis approved by the ERCOT Board (such as annually, quarterly, or monthly).

(d) The unsecured credit limit issued to any entity shall not exceed One Hundred Twenty-Five Million Dollars.

16.8.1.5.3 Alternative Means of Satisfying ERCOT Creditworthiness Requirements

If a TCR Account Holder does not meet the creditworthiness qualifications above, the TCR Account Holder may satisfy ERCOT's creditworthiness requirements through one of the following means:

(a) Another Entity that meets or exceeds the Long-Term or Issuer Rating and equity level, as established by the ERCOT Board, may provide a corporate guarantee of the TCR Account Holder's liability to ERCOT, provided that the corporate guarantee issuer shall provide annual audited financial statements not later than thirty-days (30) after the close of each of the issuer's fiscal year.

(b) The TCR Account Holder may provide an irrevocable letter of credit naming ERCOT beneficiary in an amount equal to or greater than the TCR Account Holder's maximum liability amount. ERCOT may reject the letter of credit if the issuing bank is unacceptable to ERCOT or if the conditions under which ERCOT can draw against the letter of credit are unacceptable to ERCOT.

(c) The TCR Account Holder may deposit cash in an account designated by ERCOT with the understanding that ERCOT may draw part or all of the cash deposit to satisfy any overdue payments owed by the TCR Account Holder to ERCOT. The account may bear interest payable directly to the TCR Account Holder, provided, however, any such arrangements shall not restrict ERCOT's immediate access to the funds. The cash deposit shall always be an amount equal to or greater than the TCR Account Holder's estimated and actual liability amount. Each TCR Account Holder agrees that ERCOT has a security interest in all property delivered by the TCR Account Holder to ERCOT from time to time in order to meet the creditworthiness requirements and that such property secures all amounts owed by the TCR Account Holder to ERCOT.

16.8.1.6 Monitoring of Creditworthiness by ERCOT

ERCOT shall monitor the creditworthiness of each TCR Account Holder. With respect to a TCR Account Holder that meets ERCOT creditworthiness requirements pursuant to 16.8.1.5.1, ERCOT Creditworthiness Requirements for TCR Account Holders, such TCR Account Holder shall inform ERCOT within three (3) Business Days if it experiences a material change in its ability to satisfy those credit requirements. Such TCR Account Holder must provide alternative means of security in accordance with subsection 16.8.1.5.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements. If the TCR Account Holder fails to promptly satisfy ERCOT creditworthiness requirements, then ERCOT shall suspend the TCR Account Holder's right to bid in any future TCR auction until ERCOT's creditworthiness requirements are met.

With respect to TCR Account Holders meeting creditworthiness requirements using an alternative means provided in subsection 16.8.1.5.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements, each TCR Account Holder is responsible, at all times, for maintaining security in an amount at or above its estimated and actual TCR Account Holder auction liability amount. ERCOT shall reject any bids submitted that violate ERCOT-approved credit limits.

16.8.1.7 Late Payments by Account Holders

Provisions applicable to TCR Account Holder Late Payment(s) are set forth in Section 16.2.9.2, ERCOT Remedies for Late Payments, above.

16.8.1.7.1 First Three (3) Late Payments in Any Rolling 12-Month Period

For the first three (3) Late Payments, ERCOT shall review the circumstances and reason for the Late Payments, and shall send a Late Payment notification to a Senior Representative of the TCR Account Holder.

Additionally, the third Late Payment notice will advise the Senior Representative(s) that a subsequent Late Payment in the rolling 12-month period will result in termination of the TCR Account Holder's Agreement.

16.8.1.7.2 Fourth Late Payment in Any Rolling 12-month Period

After the fourth Late Payment ERCOT shall terminate the TCR Account Holder Agreement with ERCOT, as provided in the TCR Account Holder Agreement.

16.8.1.8 Defaulting TCR Account Holder

Provisions applicable to a TCR Account Holder Default are set forth in Section 16.2.9.1, ERCOT Remedies, above.

16.8.1.9 TCR Late Payments Revenues

A TCR Account Holder shall pay late fees on any delinquent amount to ERCOT according to the late fee terms for the period from and including the relevant payment date to the final date in which the payment is due to ERCOT together with any related transaction costs incurred by ERCOT.

Any Late Payment revenues, less ERCOT's transaction costs shall be added to the annual or monthly auction revenues and distributed in accordance with Section 7.5.4, Allocation Method and Timing for Distributing TCR Auction Revenues.

16.8.1.10 Release of Account Holder's Security Requirement

ERCOT shall, following the termination of a TCR Account Holder Agreement and within thirty-days (30) of being satisfied that no sums remain owing by the TCR Account Holder under these Protocols, return or release to the TCR Account Holder, as appropriate, any security provided by the TCR Account Holder under this Section. Neither the TCR Account Holder nor any of its Affiliates will be allowed to participate in future TCR auctions or ERCOT recognized TCR transfers.

ERCOT will release a TCR Account Holder's security within five (5) Bank Business Days after written notice requesting release is received by ERCOT. However, the TCR Account Holder will not be allowed to participate in the following auctions, unless security is re-posted no less than five (5) Bank Business Days prior to open of any such auction.

16.9 Resources Providing Reliability Must Run Service or Synchronous Condenser Service

Any Entity providing Reliability Must Run Service or Synchronous Condenser Service must sign an RMR/SC Agreement. If such Entity has not already signed a Standard Form Market Participant Agreement, the Entity shall also sign a Standard Form Market Participant Agreement prior to commencing the service of any RMR/SC under these Protocols.

16.10 Resources Providing Black Start Service

Any Entity providing Black Start Service must sign a Black Start Service Agreement. If such Entity has not already signed a Standard Form Market Participant Agreement, the Entity shall also sign a Standard Form Market Participant Agreement prior to commencing the Black Start Service under these Protocols.

16.11 User Security Administrator and Digital Certificates

Each Market Participant is allowed access to ERCOT's computer systems through the use of Digital Certificates. A Digital Certificate is 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. Digital Certificates expire after a period of one (1) year. A User Security Administrator (USA) is responsible for managing the Market Participant's access to ERCOT's computer systems through Digital Certificates. Each Market Participant must, as part of the application for registration with ERCOT, designate an individual employee or authorized agent as its USA and, optionally, a secondary USA. If a Market Participant has designated a secondary USA, the secondary USA shall function in the same manner as the primary USA. The Market Participant is responsible for revising its USA list as the need arises. The Market Participant's USA is also responsible for registering all of the Market Participant's Digital Certificate holders ("Certificate Holders") and administering the use of Digital Certificates on behalf of the Market Participant. Each Market Participant with 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 will send the USA a copy of "Digital Certificate Introduction and Use for Market Participants." This document is a guide for the USA containing Digital Certificate procedures.

16.11.1 USA Responsibilities and Qualifications for Digital Certificate Holders

The USA, on behalf of the Market Participant, is responsible for the following:

(1) Requesting Digital Certificates for authorized potential Certificate Holders (either persons or programmatic interfaces) 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 (a) – (e), below.

(a) 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 will not request that Digital Certificates be issued to any employee or authorized agent it determines, after reasonable background review, poses a threat to ERCOT's market or computer systems. If the Market Participant does not utilize a background review process at the time this Section first becomes applicable to the Market Participant (*i.e.*, upon registration with ERCOT for new Market Participants), the Market Participant shall institute a process to require reasonable background reviews for the potential

Certificate Holders no later than six (6) months after this Section first applies to the Market Participant.

(b) The potential Certificate Holder is aware of the rules and restrictions relating to the use of Digital Certificates.

(c) The potential Certificate Holder is eligible to review and receive technology and software under applicable export control laws and regulations and under the Foreign Corrupt Practices Act. Information for web-listings shall be located on the MIS. If the Market Participant does not utilize an export control and Foreign Corrupt Practices Act review process at the time this Section first applies to the Market Participant, the Market Participant shall institute a process to require such reviews for potential Certificate Holders no later than six (6) months after this Section first applies to the Market Participant.

(d) The Market Participant has conducted a reasonable review of the potential Certificate Holder and is not aware that the potential Certificate Holder is one of the persons on any U.S. terrorist watch list, the link to which is located on the MIS. If the Market Participant does not utilize a terrorist watch list review process at the time this Section first applies to the Market Participant, the Market Participant shall institute a process to require such reviews for potential Certificate Holders no later than six (6) months after this Section first applies to the Market Participant.

(e) 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.

(2) Requesting revocation of Digital Certificates under any of the following conditions:

(a) As soon as possible, but no later than three (3) Business Days, after:

(i) a Certificate Holder ceases employment with the Market Participant; or

(ii) 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) such that the Certificate Holder no longer needs the Digital Certificate,

the Market Participant or USA shall request the revocation by proceeding with the ERCOT certificate revocation process.

(b) As soon as possible, but no later than five (5) 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 conditions of use of a Digital Certificate, the Market Participant or USA shall request the revocation by proceeding with the ERCOT certificate revocation process. Violations of conditions of use include:

(i) violating the requirements of 16.11.1(1) above;

(ii) using the Digital Certificate for any unauthorized purpose; or

(iii) allowing any person other than the Certificate Holder to use the Digital Certificate.

(3) 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 “Digital Certificate Introduction and Use for Market Participants.”

(4) Requesting annual renewal of Digital Certificates.

(5) If needed, issuing Digital Certificates for use by electronic systems not limited to servers.

(6) Maintaining the integrity of the administration of Digital Certificates through consistent, sound and reasonable business practices.

16.11.2 Requirements for Use of Digital Certificates

Use of Digital Certificates must comply with the following:

(1) 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 “Digital Certificate Introduction and Use for Market Participants.”

(2) 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.

(3) The Market Participant is wholly responsible for any use of Digital Certificates issued or requested by its USA.

16.11.3 Market Participant Audits of User Security Administrators and Digital Certificates

During September of each year, each Market Participant 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 "Digital Certificate Introduction and Use for Market Participants" to rectify the discrepancy. The audit must, at a minimum confirm that:

(1) The Market Participant and each listed USA and Certificate Holder meet the applicable requirements of Section 16.11.1(1) and (2);

(2) Each listed USA and Certificate Holder is currently employed by or is an authorized agent contracted with the Market Participant;

(3) The Market Participant has verified that the listed USA is authorized to be the USA;

(4) Each Certificate Holder is authorized to retain and use the Digital Certificate; and

(5) Each listed Certificate Holder needs the Digital Certificate to perform his or her job functions.

By October 1 of each year, Market Participants shall submit to ERCOT an attestation from an officer or executive with authority to bind the Market Participant, certifying that:

(1) The Market Participant has complied with the requirements of the audit;

(2) 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 Section 16.11.1(1), the USA will inform ERCOT as described in Section 16.11.1(2) and note the findings in the response; and

(3) The USA and all Certificate Holders have been qualified through a reasonable screening process.

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 such extension request and inform the Market Participant if the request is approved or denied. ERCOT will approve no more than one extension request per Market Participant.

By December 1 of each year, ERCOT will acknowledge receipt of each Market Participant audit received and indicate whether any required information is missing from the audit.

16.11.4 ERCOT Audit - Consequences of Non-compliance

ERCOT, or its designee, will review the audit results submitted under Section 16.11.3, Market Participant Audits of User Security Administrators and Digital Certificates, and may audit a Market Participant for compliance with the provisions of this subsection. The Market Participant will cooperate fully with ERCOT in such audits. On or about December 15 of each year, ERCOT shall report to the PUCT all Market Participants failing to properly perform annual audits as described in Section 16.11.3 or non-compliance with Section 16.11.3. ERCOT, after providing Notice to the Market Participant and the PUCT, may disqualify the Market Participant's USA and/or revoke any or all Digital Certificates assigned by that USA if:

(1) The Market Participant does not properly and timely perform the audit;

(2) ERCOT discovers non-compliance; or

(3) The Market Participant does not timely request revocation of Digital Certificates for unauthorized Certificate Holders.

Notwithstanding the foregoing, ERCOT shall not disqualify a Market Participant's USA or revoke a Market Participant's Digital Certificate(s) without providing the Market Participant the following options:

(1) Opportunity to work with ERCOT to resolve issues in a manner agreeable to both parties;

(2) Opportunity to authorize a new USA and assign new Digital Certificates as necessary to prevent disruption of the Market Participant's business; and/or

(3) If the Market Participant will not or cannot designate a new USA or the violation is so egregious that ERCOT determines it is inappropriate to issue new Digital Certificates, the opportunity to appeal ERCOT's decision to disqualify the Market Participant's USA and revoke its Digital Certificates to the PUCT.

ERCOT Protocols
Section 17: Market Data Collection and Use

July 1, 2001

17 MARKET DATA COLLECTION AND USE

17.1 Objectives and Scope

Market oversight in ERCOT is primarily the responsibility of the PUCT. ERCOT's market oversight responsibilities include assisting the PUCT in its efforts by collecting and retaining data, providing electronic access to the Data Warehouse and Data Archive, reporting results, and recommending changes to these Protocols, as provided in Section 21, Process for Protocols Revision, to enhance market operations. ERCOT may also be called upon to provide data to other Governmental Authorities and to Market Participants. ERCOT may include market data on the MIS discussed in Section 12, Market Information System of these Protocols.

17.2 Data Collection and Retention

17.2.1 Information System

ERCOT shall be responsible for developing and operating an information system for the collection and storage of market data required by these Protocols. ERCOT shall provide adequate communication equipment and necessary software packages to enable the PUCT to establish electronic access to the Data Warehouse and Data Archive. The Data Warehouse and Data Archive shall be designed to accommodate a remote query function by the PUCT during and outside of Business Hours.

17.2.2 Data Categories and Handling Procedures

To develop the information system set forth in Section 17.2.1, Information System, ERCOT shall initially develop, and shall refine on the basis of experience, a detailed catalog of all the categories of data it will have the means of acquiring, and the procedures it will use to handle such data (including procedures for protecting Protected Information).

17.2.3 Accuracy of Data Collection

On an on going basis, ERCOT shall apply appropriate procedures for the accurate collection of data into the Data Warehouse and accurate communication of that data for use by the PUCT. By written notice, ERCOT may require Market Participants to verify the accuracy of data previously submitted to ERCOT.

Failure by a Market Participant to provide accurate and complete information in the manner and time requested in accordance with these Protocols shall be reported to the PUCT and may be treated as grounds for action against the Market Participant.

17.2.4 PUCT Review of Data Collection

The PUCT Market Oversight Division may review the initial catalogs of information and data, as well as data collection verification criteria, developed by ERCOT in accordance with these Protocols and may propose such changes, additions, or deletions thereto as it sees fit. In so doing, the PUCT Market Oversight Division shall have discretion to specify database items or evaluation criteria for inclusion in the pertinent catalogs.

17.2.5 Data Retention

The data stored in the Data Warehouse and Data Archive shall be available online for four (4) years from ERCOT's creation or receipt of the data. Data passed to the Data Archive will be stored by ERCOT for a total of seven (7) years.

17.3 Types of Data Made Available to the PUCT

The types of data to be made available by ERCOT for PUCT market oversight includes, but is not limited to:

(1) Congestion Management

(a) Congestion cost by zone

(b) Percent of time Congestion occurs

(c) Cost per constraint

(d) Limitations on transmission system

(e) Bidding (bidders, offered quantities and prices, winning bid)

(2) Transmission Access

(a) Current scheduling (includes which transmission line was/was not available to what extent)

(b) Transmission access by TDSPs

(c) Transmission Congestion right auctions

(d) Forecast (Load and transmission)

(3) Ancillary Services (includes quantities and prices)

(a) Capacity and competitiveness of ancillary services market

(b) Accepted and unaccepted bids

(c) Ancillary services self provided versus ISO procured

(4) QSE Scheduling

(5) Customers

(a) Switches, drops, objections

(b) Customers by REP and class

(c) Electric provider, POLR, or CSA

(d) 5% Residential Minimum

(6) Load Information (amount of energy used by different companies in megawatt and megawatt hours)

(a) Load per QSE, LSE, CSC zone, profile class, etc.

(7) Generation Information

(a) Ownership (what is where, who owns what)

(b) Generation (actual), including outages, forced or not

(c) Actual operation of Generation Resource units (generation statistics)

(d) Balancing Energy Market

(e) Systems operations

(8) Pricing on types of power

(9) Demand side Resources

(10) Renewable Resources

(11) ERCOT initiated activities for market

(12) DC Ties – Inputs and Outputs

17.4 Provision of Data to Individual Market Participants

Any data requested by a Market Participant that is not available to such requesting Entity via the MIS may, on approval of the ERCOT Chief Executive Officer or designee and subject to constraints on ERCOT's resources, be provided by ERCOT to the requesting Entity; provided that this subsection shall not be construed as authorization to release Protected Information. Where such activity imposes a burden or expense on ERCOT, the data may be provided on the condition that a reasonable contribution to the cost incurred by ERCOT is made to ERCOT by the requesting Entity in accordance with the ERCOT Service Fee Schedule posted on the MIS. ERCOT shall accommodate these requests on a non-discriminatory basis.

17.5 Reports to the PUCT and the FERC

ERCOT shall make available data to the PUCT in a nightly report. The PUCT Market Oversight Division shall have discretion to specify, after consultation with ERCOT, changes, additions, or deletions to the form of the nightly report, limited to data collected by ERCOT.

ERCOT staff shall develop a schedule and format for reports to the PUCT and the FERC, which shall be submitted as a proposal to the ERCOT Board. ERCOT staff shall prepare and submit, the reports according to the schedule approved by the ERCOT Board.

17.6 Changes to Facilitate Market Operation

ERCOT shall evaluate its system operation and market performance to identify potential areas for improvements. This evaluation shall consider impacts on system operations and market performance of PUCT rules, these Protocols, ERCOT 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, but not limited to, revising its procedures, proposing changes to these Protocols through the process specified in Section 21, Process for Protocols Revision, and submitting recommendations to the PUCT or other appropriate Governmental Authorities. In performing these tasks, ERCOT shall seek comments and recommendations from the PUCT Market Oversight Division, Market Participants, and other interested Entities.

ERCOT Protocols
Section 18: Load Profiling

May 1, 2009

18 LOAD PROFILING

18.1 Overview

The ERCOT retail market requires a fifteen (15) minute Settlement Interval, yet the vast majority of Customers do not have the metering necessary to measure their consumption at this level of granularity. Load Profiling provides a cost-effective way of estimating fifteen (15) minute Load for these Customers, enables the accounting of their energy usage in the market settlement process, and allows the participation of these Customers in the retail market.

This Section details how Load Profiling will be implemented in ERCOT.

18.2 Methodology

ERCOT will develop Load Profiles for both non-interval metered Loads and Non-Metered Loads. 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.

The following Load Profiling methods will be used:

Type of Load	**Load Profiling Methodology**
non-interval metered	adjusted static models
non-interval metered with Distributed Renewable Generation (DRG)	adjusted static models and engineering estimates
non-metered	engineering estimates

Load Profiles will also be developed for Interval Data Recorders (IDRs) for use in settlements when actual IDR data is not available. All Load Profiles will conform to the ERCOT-defined Settlement Interval length.

Adoption of a new methodology requires approval of the Technical Advisory Committee (TAC), without the necessity of complying with the procedures in Section 21, Process for Protocol Revision. The TAC shall establish the implementation date for approved changes, as the TAC deems appropriate, recognizing the magnitude of the impacts on Market Participants.

[PRR766: Replace Section 18.2 above with the following upon system implementation:]

ERCOT has developed Load Profiles for both non-interval metered Loads and Non-Metered Loads. 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.

The following Load Profiling methods will be used:

Type of Load	**Load Profiling Methodology**
non-interval metered	adjusted static models
non-interval metered with Distributed Renewable Generation	adjusted static models and engineering estimates
non-metered	engineering estimates

Load Profiles will also be developed for Interval Data Recorders (IDRs) and Advanced Meters for use in settlements when actual 15-minute data is not available. All Load Profiles shall conform to the ERCOT-defined Settlement Interval length.

Adoption of a new methodology requires approval of the Technical Advisory Committee (TAC), without the necessity of complying with the procedures in Section 21, Process for Protocol Revision. The TAC shall establish the implementation date for approved changes, as the TAC deems appropriate, recognizing the magnitude of the impacts on Market Participants.

18.2.1 Guidelines for Development of Load Profiles

In developing Load Profiles, ERCOT shall strive to achieve an optimal combination of the following:

(1) Give no unfair advantage to any Entity;

(2) Maximize usability by minimizing the total number of Load Profiles without compromising accuracy and cost effectiveness;

(3) Minimize the Load Profiles' contribution to Unaccounted for Energy (UFE) over all Settlement Intervals, paying particular attention to higher cost periods;

(4) Reflect reasonably homogenous groups, with respect to Load shape and likely supply costs;

(5) Develop Load Profiles that are distinctly different;

(6) Develop Load Profiles for areas with incomplete Load data utilizing data from other sources, taking into account similarities and differences in Load;

(7) Accommodate Time Of Use (TOU) rate classes;

(8) Use the most accurate Load research data available; and

(9) 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 Without Distributed Renewable Generation

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.

18.2.3 Load Profiles for Non-Interval Metered Loads With Distributed Renewable Generation

Load Profiles for non-interval metered Loads that utilize DRG (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.

18.2.4 Load Profiles for Non-Metered Loads

Load Profiles will be created for Non-Metered Loads, e.g., streetlights, traffic signals, security lighting, billboards, parking lots, etc. These Load Profiles will be created by using engineering estimates based on known criteria, such as hours of operation, with appropriate variation in sunrise/sunset times when suitable. Transmission and/or Distribution Service Providers (TDSPs) are responsible for providing monthly consumption (kWh) for non-metered Electric Service Identifiers (ESI IDs).

18.2.5 Generic Load Profiles for Interval Data Recorders

Generic or default Load Profiles will be developed for IDRs. These profiles will only be used when no historic Customer-specific interval data is available for settlements. The “adjusted static” methodology will be used to create these Load Profiles.

For details on the method to estimate IDR data for settlement purposes, refer to Section 11, Data Acquisition and Aggregation.

18.2.6 Identification of Weather Zones and Load Profile Types

ERCOT, in coordination with the appropriate ERCOT TAC subcommittee, will identify Weather Zones and Load Profile Types based on an analysis of the Load research data, weather data, effects of power price changes from interval to interval, and sunrise/sunset data.

18.2.7 Daily Profile Creation Process

ERCOT will maintain Load Profile models to create profiles for the target settlement day (backcast) and three (3) 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.

18.2.8 Maintenance of Samples and Load Profile Models

ERCOT, in coordination with TDSPs, shall periodically monitor, review, and maintain the validity and accuracy of the Load research samples and the Load Profiling models. ERCOT shall take the necessary action to alleviate any situations whereby Load Profiles are no longer representative.

18.2.8.1 Sample Maintenance

ERCOT will review Load research sample validity (e.g., difference-of-means test) at the following times: 1) at least annually, and 2) when discrepancies (such as excessive UFE) or disputes warrant.

ERCOT will monitor and review this Sampling in accordance with ERCOT Protocols, the Load Profiling Guide, and the most current Association of Edison Illuminating Companies (AEIC) Load Research manual.

18.2.8.2 Model Maintenance

ERCOT shall monitor the applicability of the Load Profiling models by comparing all available actual interval data samples with estimates generated from the profile model by interval for the same time period. Should these comparisons reveal significant discrepancies, ERCOT should take appropriate action and coordinate with the appropriate ERCOT TAC subcommittee.

18.2.9 Adjustments and Changes to Load Profile Development

ERCOT and the appropriate ERCOT TAC subcommittee will conduct an ongoing evaluation of the current Load Profiling Methodology. Together they will determine whether appropriate changes to the methodology should be made or whether another approach or combination of approaches is warranted. Any Market Participant may request a review of the Load Profiling

Methodology. Adoption of a new Load Profiling Methodology must be approved by the TAC, as provided in Section 18.2, Methodology.

Any Market Participant may petition ERCOT for adjustments to the existing Load Profiles and for development of new Load Profiles. The Market Participant making the request shall submit their proposal in writing to ERCOT. ERCOT will post to the Market Information System (MIS) the request and respond to such requests within sixty (60) days. ERCOT shall coordinate with the appropriate ERCOT TAC subcommittee for each change request. ERCOT shall strive to make the necessary changes within a reasonable period of time.

ERCOT, in coordination with the appropriate ERCOT TAC subcommittee, may make changes to existing Load Profiles and establish additional Load Profiles. All changes to Load Profiles shall adhere to these Protocols. When additional Load Profiles are established, ERCOT shall evaluate the impact on existing Load Profiles and associated Load research samples.

A Market Participant may submit a request to ERCOT for conditional approval of a new Load Profile segment following the approval process as specified in the Load Profiling Guide, Section 12, Request for Profile Segment Changes, Additions, or Removals. In conjunction with this request, ERCOT shall specify the requirements for additional Load research sampling and shall define specific and objective criteria to be met by the analysis of this Load research data to meet the requirements for final approval. Provided the request for conditional approval has received the appropriate ERCOT committee approval and ERCOT determines the specified criteria are met, the request shall be granted final approval. If ERCOT determines the specified criteria are not met, the request shall be denied.

Section 9.9, Profile Development Cost Recovery Fee for a Non-ERCOT Sponsored Load Profile Segment, describes the process for compensating the originator of a profile segment change request by Competitive Retailers (CRs) wishing to subscribe to the profile segment.

ERCOT shall give at least one hundred fifty (150) days notice to all Market Participants prior to market implementation of any change in Load Profile 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, TDSPs shall send any revised ESI ID Load Profile 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.

If one or more Load Profiles require changes to reduce excessive UFE, as determined by the appropriate ERCOT 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 Profile Methodology requires changes to reduce excessive UFE, as determined by the appropriate ERCOT TAC subcommittee, TAC may provide an expedited notice period and implementation date. TAC may require the standard Load Profile revision process follow such expedited revisions for long-term resolution.

18.2.10 Special Requirement for Profiling Sample Points

When a Premise is used as part of a Load research sample for Load Profiling, and that Premise or that Premise's CR elects to use its interval data for settlement purposes, it will be necessary to replace that Premise in the sample. It will be incumbent on ERCOT to coordinate this type of change with the TDSP, if appropriate.

18.2.11 Responsibilities for Sampling in Support of Load Profiling

18.2.11.1 ERCOT Sampling Responsibilities

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.

18.2.11.2 Transmission and/or Distribution Service Provider Sampling Responsibilities

The TDSPs' Load research data are critical for Load Profile development by ERCOT. TDSPs, other than Non-Opt In Entities (NOIEs), shall provide available Load research data when requested by ERCOT.

The TDSPs, other than NOIEs, shall provide ERCOT at least one (1) year notice of any significant change in the status of the TDSPs' Load research programs.

TDSPs shall address the appropriate ERCOT TAC subcommittee as a forum for their input in the development and refinement of Load Profiles.

TDSPs shall follow the rules and procedures as specified in PUCT rules.

ERCOT may request from TDSPs, and such TDSPs shall provide, the most current Load research data reasonably available to aid in the development or refinement of Load Profile models, subject to Section 18.2.9, Adjustments and Changes to Load Profile Development.

18.3 Posting

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 and regulations.

18.3.1 Methodology Information

A complete description of all supporting models, documentation and data used in preparation of Load Profiles will be made available on the Market Information System (MIS), including:

(1) The historic Load data used to create the Load Profiles;

(2) Average interval accuracy of each Load Profiling model;

(3) Weather information;

(4) Sunrise/sunset information;

(5) Updates of Transmission and/or Distribution Service Provider (TDSP) Load research data as it becomes available to ERCOT; and

(6) Any other data used for Load Profile development.

18.3.2 Load Profiling Models

ERCOT will make available the models used to produce the forecast and backcast profiles for the settlement process. The Load Profile models shall be accessible via the MIS in a downloadable format.

18.3.3 Load Profiles

ERCOT will publish Load Profile data from the profile creation process, in accordance with Section 18.2.7, Daily Profile Creation Process, to the MIS and through the common Automated Programmatic Interface (API). Load Profile data will be made available to Market Participants for a period of two (2) years.

ERCOT will post to the MIS by 1000 each Business Day forecasted Load Profiles for the three (3) following days for each Load Profile Type and Weather Zone. Backcast profiles for each Load Profile Type and Weather Zone will be available by 1000 of the second (2nd) 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

Each Electric Service Identifier (ESI ID) is required to be associated with an appropriate Load Profile ID. 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

ERCOT shall develop a cross-reference table of all Load Profile ID used in the ERCOT market. The table shall clearly state class relationship to Load Profile Type. This information shall be made accessible, on the Market Information System (MIS), to all Market Participants. 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

ERCOT and the appropriate ERCOT Technical Advisory Committee (TAC) subcommittee shall review the Load Profile ID assignment process on an annual basis, make recommendations for enhancements, and evaluate the integration of the validation and assignment processes.

Any Market Participant may request temporary changes to the yearly process for assigning and validating Load Profile IDs to address unusual circumstances. Such requests shall be submitted to the appropriate ERCOT TAC subcommittee. If the request is approved by the ERCOT TAC subcommittee, it shall then be submitted to the TAC. Change requests as a result of an extreme event such as a hurricane or ice storm may be submitted directly to the TAC. Such requests, if approved by the TAC, shall be in effect only for the requested year.

Should there be any change in Load Profile ID assignment to any ESI ID, it will be the responsibility of the Transmission and/or Distribution Service Provider (TDSP) to submit those changes to ERCOT.

18.4.3 Validation of Load Profile Type and Weather Zone Assignments

In this section validation shall mean performing checks to ensure correct assignment of ESI IDs to Load Profile Types and Weather Zones.

18.4.3.1 Validation Tests

This section refers to validation of the assignment of Load Profile Type and Weather Zone to ESI IDs.

Validation tests of Load Profile Type and Weather Zone assignments, at a minimum, will occur at the following times: initial Load Profile ID assignment, when a change is made in the Load Profile Type or Weather Zone assignment, and at least one (1) time per year.

ERCOT may utilize a Sampling method for Load Profile Type assignment validation and when a change is made in the Load Profile ID assignment.

ERCOT shall validate the assignment of the Weather Zone component of the Load Profile ID for all ESI IDs.

ERCOT shall perform validation tests of the initial Load Profile Type and Weather Zone assignments of each TDSP. Samples of assignments from the Residential and Business Profile Groups will be randomly drawn from each TDSP's population of profiled ESI IDs. If the assignment validation failure rate for any of these samples exceeds parameters specified in the Load Profiling Guide, ERCOT may request an audit of the corresponding TDSP's Load Profile ID assignment processes and systems at the expense of the TDSP. ERCOT may require TDSPs that fail sample Load Profile Type or Weather Zone assignment validations and/or audits to resubmit Load Profile ID assignments for all ESI IDs in their service territory.

Details of all validation tests will be specified in the Load Profiling Guide. Competitive Retailers (CRs) may dispute a Load Profile ID assignment through the ERCOT settlement dispute process, as described in Section 9.5, Settlement and Billing Dispute Process, in conjunction with the Load Profiling Guide.

TDSPs shall change the assignment of a Load Profile ID for the single ESI ID based on an outcome of a dispute finding in favor of a CR. If required to change an assignment, TDSPs must correct the assignment in their system and the ERCOT Customer registration system within three (3) Business Days.

18.4.3.2 Correction Procedure

TDSPs are responsible for investigating each ESI ID identified by ERCOT as having a potentially incorrect Load Profile ID assignment. Each TDSP shall work closely and promptly with ERCOT during the correction procedure, which is detailed in the Load Profiling Guide.

Market Participants may dispute an assignment through the ERCOT settlement dispute process, described in Section 9.5, Settlement and Billing Dispute Process, of these Protocols.

18.4.4 Assignment of Weather Zones to ESI IDs

TDSPs will assign each ESI ID to a Weather Zone, based on service address zip code.

ERCOT will post to MIS a mapping of a Weather Zone to appropriate Customer registration element used in assigning Weather Zones.

18.5 Additional Responsibilities

This section addresses responsibilities for Load Profiling not specified in other Sections of the Protocols.

18.5.1 ERCOT Responsibilities

ERCOT will develop, administer, and maintain Load Profiles in accordance with these Protocols. Disputes related to the accuracy or appropriateness of Load Profiles shall be handled in accordance with Section 9.5, Settlement and Billing Dispute Process.

18.5.2 Transmission and/or Distribution Service Provider Responsibilities

Transmission and/or Distribution Service Providers (TDSPs) shall use the appropriate ERCOT Technical Advisory Committee (TAC) subcommittee as a forum for their input in the development and refinement of Load Profiles.

18.5.3 Competitive Retailer Responsibilities

Competitive Retailers (CRs) shall use the appropriate ERCOT TAC subcommittee as a forum for their input in the development and refinement of Load Profiles.

CRs shall be responsible for reviewing any assignment of Load Profiles to Electric Service Identifier (ESI IDs) they represent.

18.6 Installation and Use of Interval Data Recorders

18.6.1 Interval Data Recorder Installation and Use in Settlement

(1) Interval Data Record (IDR) Mandatory Installation Threshold: IDRs shall be installed and utilized for settlement of Premises having either:

a. A peak Demand greater than 700 kW (or 700 kVA), or

b. Service provided at transmission voltage (above 60 kV).

For the IDR installation process at Premises that meet the IDR Mandatory Installation Threshold identified above, refer to the Retail Market Guide Section 7.13.2.2, Mandatory IDR Installation Process.

(2) A Competitive Retailer (CR), upon a Customer's request or with a Customer's authorization, may have an IDR installed and used for settlement purposes at any associated Premise outside the IDR Mandatory Installation Threshold. Except as stated in item (4) of this Section, IDRs in place or installed after September 1, 1999 shall be used for settlement. Once an IDR is installed on a Premise and used for settlement purposes, the given Premise shall continue to be settled with its interval data, except as stated in Sections 18.6.7, Interval Data Recorder Optional Removal Threshold. If a Customer or CR requests installation of an IDR meter, the same Customer may not request removal of the IDR meter for a period of twelve (12) consecutive months following such installation.

(3) 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 Threshold. These Loads shall be settled using Load Profiles.

(4) For Premises not subject to the IDR Mandatory Installation Threshold in item (1) of this Section:

(a) IDRs installed at the request of ERCOT, a Transmission and/or Distribution Service Provider (TDSP), a municipal, or a cooperative for Load research, rate/tariff design calculation, coincident Demand calculation, or Load Profiling purposes shall be exempt from the requirement to use an IDR for settlement purposes; or

(b) IDRs previously used specifically for separating Non Opt-In Entity (NOIE) Load from competitive Load shall be exempt from the requirement to use an IDR for retail Customer settlement purposes, provided that the IDR meter has been removed within one hundred and twenty (120) consecutive days after the NOIE has fully implemented Customer Choice. IDR meters used for NOIE separation that do not meet the IDR Mandatory Installation Threshold shall not be used for retail Customer settlement purposes.

(5) For IDR installation procedures reference Section 10.2.2, TDSP Metered Entities.

(6) TDSPs responsible for any Load transfer schemes between ERCOT and Non-ERCOT Regions shall install IDR metering capable of measuring the Load served during the period the Load transfer is implemented.

18.6.2 Interval Data Recorder Administration Issues

ERCOT shall produce a report informing the appropriate Market Participants of profiled Premises that have become subject to the provisions of item (1) of Section 18.6.1, Interval Data Recorder Installation and Use in Settlement, IDR Mandatory Installation Threshold. ERCOT shall put in place a system to track Market Participants' timely adherence to this requirement. This report shall be posted to Market Information System (MIS).

18.6.3 Adherence to Interval Data Recorder Requirements

Municipal Entities and Electric Cooperative Entities that opt-in to Customer Choice must install IDR meters at all Premises subject to the IDR Mandatory Installation Threshold for metering prior to the effective date of their participation in the testing and integration requirements of ERCOT systems for Customer Choice.

18.6.4 Technical Requirements

Regardless of data retrieval method, interval data shall be provided on a schedule that supports the requirements of final settlement (typical monthly billing cycle).

Interval data that is provided for settlement shall be consistent with the ERCOT defined Settlement Interval.

IDRs used for settlement shall meet technical metering requirements defined in the Load Profiling Guide.

18.6.5 Future Requirements for Interval Data Recorders

ERCOT and the appropriate ERCOT Technical Advisory Committee (TAC) subcommittee shall evaluate the impact of the IDR Mandatory Installation Threshold as defined in this Section for possible revision prior to the introduction of competitive metering services to the market on January 1, 2004.

18.6.6 Peak Demand Determination for Non-Interval Data Recorder Premises

For the purpose of determining the peak Demand level for the IDR Mandatory Installation Threshold in Section 18.6.1, Interval Data Recorder Installation and Use in Settlement, the Demand will be determined in accordance with Public Utility Commission of Texas (PUCT) rulemaking or through a consensus process with ERCOT and Market Participants. In the absence of a clear definition of peak Demand in the Price-to-Beat rulemaking, the following application shall be used in determining the peak Demand level for IDR Mandatory Installation Threshold in Section 18.6.1:

A Premise (Electric Service Identifier (ESI ID)) has a peak Demand greater than the applicable level in Section 18.6.1 when measured in any two (2) billing months of the most recent twelve (12) month period. CRs may dispute an IDR assignment through the ERCOT settlement dispute process, described in Section 9.5, Settlement and Billing Dispute Process.

ERCOT shall be responsible for receiving and storing Demand information necessary for determining mandatory IDR installations.

18.6.7 Interval Data Recorder Optional Removal Threshold

The CR, upon a Customer's request or with a Customer's authorization, may request, in accordance with PUCT rules and regulations, removal of an IDR at the Customer's Premise unless service to the Premise is provided at transmission voltage (above 60 kV). However, once the Customer's Demand at the Premise either meets or exceeds the IDR Mandatory Installation Threshold identified in paragraph (1) of Section 18.6.1, Interval Data Recorder Installation and Use in Settlement, the IDR will no longer qualify for removal.

The IDR Optional Removal Threshold for a Premise is established as follows:

(1) for an existing Customer with a Profile Type code of BUSIDRRQ, where the Load at the Premise has not exceeded the IDR Optional Removal Threshold of one hundred and fifty (150) kW (kVA) during the most recent twelve (12) consecutive months unless the existing Customer requested or authorized installation of an IDR pursuant to item (2) of Section 18.6.1, in which case the existing Customer may not request removal of the IDR for a period of twelve (12) consecutive months following such installation; or

(2) for a new Customer move-in, where the request is communicated to the CR within one hundred and twenty (120) consecutive days of the move-in provided the new Customer's Demand at the Premise has remained below the IDR Mandatory Installation Threshold

between the move-in date and the date the request is received, and that meter readings covering at least forty-five (45) consecutive days of usage at the Premise have been registered for the new Customer.

Once an IDR has been removed at a Premise by request, an IDR may not be reinstalled at that Premise for a period of twelve (12) consecutive months following such removal, unless a change in Customer(s) has taken place at that Premise during the twelve (12) month period or unless the IDR Mandatory Installation Threshold pursuant to item (1) of Section 18.6.1, has been met. Removal or re-installation of an IDR is subject to applicable tariff charges.

18.7 Supplemental Load Profiling

ERCOT and the appropriate ERCOT Technical Advisory Committee (TAC) subcommittee recognize the possible need to accommodate Load Profiling for programs or pricing schemes that encourage a Demand response to price in the retail market. Accordingly, Load Profiling methods other than adjusted static methodology are necessary.

18.7.1 Load Profiling of Time Of Use Metered Electric Service Identifier

18.7.1.1 Overview

A Time Of Use (TOU) meter is a programmable electronic device capable of measuring and recording electric energy in pre-specified time periods. For Load Profiling purposes this definition does not include Interval Data Recorders (IDRs). For additional information regarding TOU, reference the Load Profiling Guide.

The ERCOT Data Aggregation System (DAS) and settlement system must be able to collect and handle TOU meter data. The profiling of premises participating in TOU programs requires TOU meter reads so that consumption can be distributed within the appropriate time periods.

18.7.1.2 Methodology for Load Profiling of Time Of Use

The selected technique for generating profiles for TOU Premises is described as follows:

(1) Each TOU Premise is assigned to a standard Load Profile Type.

(2) Upon agreement between the Competitive Retailer (CR) and Transmission and/or Distribution Service Provider (TDSP), a Time Of Use Schedule (TOUS) is submitted by the TDSP to the ERCOT DAS, which identifies the TOU period associated with each Settlement Interval. The number of TOU periods is determined by the number of periods for which the meter will capture kWh. These periods may include on-peak, off-peak, and shoulder periods. The DAS shall collect and maintain the attributes of the TOUS (e.g., start and stop time, day of the week, season, etc.).

(3) CRs shall communicate to TDSPs their Electric Service Identifiers (ESI IDs) associated with the proper TOUS.

(4) The TDSP shall communicate all TOUSs to DAS so that proper TOUS identification for each Premise will occur in the ERCOT central database.

(5) The ERCOT DAS shall use the standard Load Profile assigned to each TOU Premise and scale the energy for each TOU period in the Load Profile so that it is equal to the metered energy (kWh) for the TOU period.

(6) TOU Load Profiling will not use TOU Demand values.

18.7.1.3 Collection of Time Of Use Meter Data

TDSPs will be responsible for providing the meter reads necessary to support TOUS available in their service territory. The ERCOT DAS shall collect and handle multiple TOU reads for each Settlement Interval. These Settlement Intervals may include on-peak, off-peak, and shoulder periods.

18.7.1.4 Availability of Time Of Use Schedules

The availability of TOUSs will be dependent on the following:

(1) TDSPs shall continue to support TOUSs available under tariffs in effect prior to December 31, 2000.

(2) The implementation of any new or modified TOUS is subject to the ERCOT and Texas Standard Electronic Transaction (TX SET) change control process.

18.7.1.5 Post Market Evaluation

Starting at the first completed settlement cycle, ERCOT and the appropriate ERCOT TAC subcommittee shall periodically review the selected profiling technique of TOU ESI IDs for accuracy, and validity. They may recommend enhancements, modifications, or a complete replacement of the technique.

18.7.2 Other Load Profiling

ERCOT, in coordination with the appropriate ERCOT TAC subcommittee, may develop Load Profiles for particular Customer segments that may require special Load Profiling techniques similar in nature to TOU and Direct Load Control (DLC) programs. Details are specified in the Load Profiling Guide.

ERCOT Protocols
Section 19: Texas Standard Electronic Transaction

September 1, 2008

19 TEXAS STANDARD ELECTRONIC TRANSACTION

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 implementation guidelines, which will be posted on the Market Information System (MIS) maintained by ERCOT. The specific implementation guidelines are not included either in the body of these Protocols or as an attachment to these Protocols.

19.1 Overview

TX SET describes the standard electronic data transactions, implementation guides, Protocols, principles and procedures that enable and facilitate the processes of Customer Choice in the deregulated Texas electric market. The full implementation guidelines and change control process documents shall be published on the MIS by ERCOT and shall define and serve as the standard electronic Protocols for the applicable TX SET transactions among all Market Participants (MPs) and ERCOT.

This Section shall cover:

(1) Transactions between Transmission and/or Distribution Service Providers (TDSPs) (refers to all TDSPs unless otherwise specified) and Competitive Retailers (CRs) and ERCOT.

(2) Subcommittee and ERCOT responsibilities.

(3) Change control process.

19.2 Methodology

In developing and maintaining the implementation guides, the appropriate ERCOT Technical Advisory Committee (TAC) subcommittee, or its designated working group shall:

(1) Develop standardized transactions, which support documented ERCOT market business requirements across all MPs and ERCOT;

(2) Develop Electronic Data Interchange (EDI) transactions using ANSI ASC X12 standards;

(3) Develop Extensible Markup Language (XML) transactions as needed;

(4) Develop other spreadsheets, templates, comma separated value (CSV) files, etc. as needed;

(5) Develop processes and procedures to be followed in the development of TX SET;

(6) Follow 'Best Practices' as identified in the overall technology market place related to development of TX SET;

(7) Develop and follow processes and procedures and follow these for the management of changes to TX SET; and

(8) Develop and follow processes and procedures for the release of new versions of TX SET.

19.3 Texas Standard Electronic Transaction Definitions

19.3.1 Defined Texas SET Transactions

(1) Service Order Request (650_01)

This transaction set:

From the CR to the TDSP via point to point Protocol, is used to initiate the original Service Order Request, Cancel Request, or Change/Update Request.

For every 650_01, Service Order Request there will be a 650_02, Service Order Response transaction.

(2) Service Order Complete, Complete Unexecutable, Reject Response, or Notification of Permit Required (650_02)

This transaction set:

From the TDSP to the CR via point to point Protocol, is used to send a Complete, Complete Unexecutable, Reject, or Notification of Permit Required Response to the CR's original, Cancel Request, or Change/Update Service Order Request.

For every 650_01, Service Order Request there will be a 650_02, Service Order Response transaction

(3) Suspension of Delivery Service Notification or Cancellation (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 Notification or to cancel the Suspension of Delivery Service Notification.

(b) From Municipally Owned Utility/Electric Cooperative (MOU/EC) TDSP to CR, used to notify CR of disconnect/reconnect of delivery service for non-payment of wires charges.

(4) Suspension of Delivery Service Reject Response (650_05)

This transaction set:

From the CR to the TDSP, is used to notify the TDSP of a rejection of a Suspension of Delivery Service Notification or rejection of a Cancellation of a Notification of Suspension of Delivery Service. The CR can only reject for invalid data.

(5) TDSP to CR Invoice (810_02)

This transaction set:

From the TDSP to the CR, is an Invoice for wire charges as listed in each TDSP Tariff, (i.e., delivery charges, Late Payment charges, discretionary service charges, etc.). This TX SET transaction may be paired with an 867_03 (Monthly Usage) to trigger the Customer billing process.

(6) CR to MOU/EC TDSP Invoice (810_03)

This transaction set:

From the CR to the MOU/EC TDSP, is an Invoice for monthly energy charges, discretionary, and service charges for the current billing period. This transaction set will be preceded by an 867_03 (monthly usage) to trigger the Customer billing process.

(7) Maintain Customer Information Request (814_PC)

This transaction set:

(a) From a CR to the TDSP, 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) This transaction set will be transmitted from the CR to the TDSP only after the CR has received an 867_04 Initial (Start) Meter Reading 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 an 867_03, final meter read for that specific move-out Customer.

(c) From a MOU/EC TDSP to CR, is used to provide 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, or from the CR to MOU/EC TDSP, is used to respond to the 814_PC, Maintain Customer Information Request.

(9) Enrollment Request (814_01)

This transaction set:

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

(10) Enrollment Reject Response (814_02)

This transaction set:

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

(11) Switch/Move-In CR Notification Request (814_03)

This transaction set:

From ERCOT to the TDSP, passes information from the 814_01, 814_16, or 814_24 (move-out where Continue Service Agreement (CSA) exists), with the addition of two data elements:

(a) The TDSP associated with this Premise; and

(b) The available switch date.

This transaction set will be initiated by ERCOT and transmitted to the TDSP in the event of a Mass Transition.

(12) Switch/Move-In CR 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 Enrollment Request, Move-In Request, Move-Out to CSA Request initiated by a CR or a Mass Transition of Electric Service Identifiers (ESI IDs) initiated by ERCOT. The historical usage, if requested by the submitter of the initiating transaction, will be sent using the 867_02 transaction.

(13) Switch/Move-In Response (814_05)

This transaction set:

From ERCOT to the new CR is essentially a pass through of the TDSP's 814_04, Switch/Move-In CR Notification Response information. This transaction will complete the new CR's Enrollment Request.

(14) Drop Due to Switch/Move-In Request (814_06)

This transaction set:

From ERCOT to the current CR, is used to notify a current CR of a drop initiated by a Enrollment Request or drop notification due to a pending move-in from a new CR.

(15) Drop Due to Switch/Move-In Response (814_07)

This transaction set:

From the current CR to ERCOT, is used to respond to the 814_06 initiated by an Enrollment/Move-In Request. If rejected, this transaction will trigger the CR objection process, as allowed by Public Utility Commission of Texas (PUCT) rules.

(16) Cancel Switch/Move-In/Move-Out/Mass Transition DropRequest (814_08)

This transaction set:

(a) From ERCOT to the TDSP, is used to cancel an Enrollment Request, a Move-In Request, a CSA Move-In Request, Move-Out Request, or Mass Transition Drop Request.

(b) From ERCOT to the current CR, is used to cancel a Drop Due to Switch (forced Move-Out or Switch) Request, a Move-Out Request, or a Mass Transition Drop Request.

(c) From ERCOT to the new CR, is used to cancel an Enrollment Request, a Move-In Request, or a Mass Transition Drop Request.

(d) From the current CR to ERCOT, is used to cancel a Move-Out Request. (e) From the new CR to ERCOT, is used to cancel an Enrollment Request or a Move-In Request.

(f) From ERCOT to the CSA CR, is used to cancel a CSA Move-In Request.

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

(17) Cancel Switch/Move-In/Move-Out/Mass Transition Drop Response (814_09)

This transaction set:

(a) From the TDSP to ERCOT, is used in response to the cancellation of an Enrollment Request, a Move-In Request, a CSA Move-In Request, Move-Out Request, or a Mass Transition Drop Request.

(b) From the current CR to ERCOT, is used in response to the cancellation of a Drop Due to Switch (forced move-out or switch) Request, a Move-Out Request, or a Mass Transition Request.

(c) From the new CR to ERCOT, is used in response to the cancellation of an Enrollment Request, a Move-In Request, or a Mass Transition Drop Request.

(d) From ERCOT to the current CR, is used in forwarding the response of the Customer cancel of a Move-Out Request.

(e) From (CSA) CR to ERCOT, is used in response to the cancellation of a CSA CR Move-In Request.

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

(g) From POLR to ERCOT, is used in response to the cancellation of pending transactions due to a Mass Transition.

(18) Drop to Affiliate REP (AREP) 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)

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(19) Drop Response (814_11)

This transaction set:

(a) ERCOT will send a reject response using the 814_11, Drop Response within one (1) Retail Business Day to the current or notifying the CR that the request is invalid.

(b) From ERCOT to the current CR in response to a Mass 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 Move-In Request.

(b) From ERCOT to the current CR is a notification of the date change on the Move-In Request from the new CR.

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

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

(e) From ERCOT to the New CR is notification of the date change on the Move-Out Request from the current CR.

(f) From ERCOT to the CSA CR, is used for a notification of a date change on the Move-Out Request 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 used to respond to the requested date change to the original move-in date on the 814_12, Date Change Request sent by the new CR.

(c) From the CSA CR to ERCOT is used to respond to the requested date change to the original move-out date on the 814_12, Date Change Request.

(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, Date Change Request.

(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, Date Change Request.

(f) From the new CR to ERCOT, is used to respond to the requested date change to the original move-out date on the 814_12, Date Change Request sent by the current CR.

(22) Drop Enrollment Request (814_14)

This transaction set:

From ERCOT to the POLR or designated CR in response to a Mass Transition.

(23) Drop Enrollment Response (814_15)

This transaction set:

From POLR or designated CR to ERCOT in response to a Mass Transition.

(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 on the basis of 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 a 814_05 Switch/Move-In Response.

(26) Establish/Delete CSA CR 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 (Continuous Service Agreement) CR 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 CR 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_18Establish/Delete CSA CR Request deleting the current CR from the registration system.

(c) From the current CSA CR to ERCOT is used to respond to the 814_18 Establish/Delete CSA CR Request notifying the current CSA CR that the owner/landlord has selected a new CSA CR.

(d) From the MOU/EC TDSP to ERCOT is used to provide a response to the 814_18.

(28) Create/Maintain/Retire ESI ID 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) Create/Maintain/Retire ESI ID Response (814_21)

This transaction set:

(a) From ERCOT to TDSP, is used to respond to the 814_20, Create/Maintain/Retire ESI ID Request.

(b) From the current CR and any pending CR(s) to ERCOT, is used to respond to the 814_20, Create/Maintain/Retire ESI ID Request.

(c) From the new CR to ERCOT, is used to respond to the 814_20, Create/Maintain/Retire ESI ID Request.

(30) Continuous Service Agreement (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 (Continuous Service Agreement) CR Move-In Response (814_23)

This transaction set:

From the CSA CR to ERCOT is used to respond to the 814_22, CSA CR Move-In Request.

(32) Move-Out Request (814_24)

This transaction set:

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

(b) From ERCOT to the TDSP, is notification of the Customer's Move-Out Request. If a CSA agreement exists on the ESI ID, then the 814_03, Switch/Move-In CR 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 agreement exists on the ESI ID and ERCOT sent the 814_03, Switch/Move-In CR Notification Request instead of the 814_24 Move-Out Request, the TDSP will then respond with the 814_04 Switch/Move-In CR Notification Response.

(b) From ERCOT to the current CR is used to respond to the 814_24, Move-Out Request.

(34) Ad-hoc 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, Ad-hoc Historical Usage Request.

(35) Ad-hoc Historical Usage Response (814_27)

This transaction set:

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

(b) From ERCOT to the current CR, is a pass through of the TDSP's response to the 814_26, Ad-hoc Usage Request.

(36) Completed Unexecutable or Permit Required (814_28)

This transaction set:

(a) Is for move-ins and move-outs where a permit is required, or the work is not completed for some reason (completed unexecutable).

(b) For a move-out, this transaction 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.

(c) For a move-in, this transaction 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 completed unexecutable, or that a permit is required. Upon sending this transaction to notify the new CR of a completed unexecutable, the TDSP closes the initiating transaction. The new CR must initiate corrective action and resubmit the Move-In Request.

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

(37) Response to Completed Unexecutable or Permit Required (814_29)

This transaction set:

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 (and to the current CR for a move-in of an energized account) is used to notify the TDSP that the CR has received the 814_28, Response to Completed Unexecutable or Permit Required or to reject the 814_28, for invalid data. The CR is not permitted to reject the 814_28 for any other reason.

(38) CR Remittance Advice (820_02)

This transaction set:

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. This transaction will reference the 810_02 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 must be forwarded to the payer's financial institution and be supported by the payee's financial institution.

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) Remittance Advise (820_03)

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. 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 must be forwarded to the payer's financial institution and be supported by the payee's financial institution.

(40) Application Advice (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, Invoice sent by the TDSP.

(b) From ERCOT to the TDSP to reject the 867_03, Monthly Usage transactions sent by the TDSP.

(c) From the CR to ERCOT to reject the 867_03, Monthly Usage transactions sent by ERCOT.

(d) From the MOU/EC TDSP to the CR is used to reject the 810_03 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, it is essentially a pass through of the TDSP's 867_02, Historical Usage.

(42) Monthly 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 Usage.

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

(43) Initial Meter Read Notification (867_04)

This transaction set:

(a) From the TDSP to ERCOT is used to report the initial read associated with a Enrollment Request or a Move-In Request.

(b) From ERCOT to the new CR is used to report the initial read associated with a Enrollment Request or a Move-In Request.

(44) Functional Acknowledgement (997)

This transaction set:

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 ANSI X12 validation. This acknowledgement does not imply that the originating transaction passed TX SET validation. CR, TDSP, or ERCOT shall respond with a 997 within 24 hours of receipt of an inbound transaction.

Functional Acknowledgements provide a critical audit trail. All parties must send Functional Acknowledgements (FA/997) for all EDI transactions. Parties will track and monitor acknowledgements sent and received.

(45) Unplanned 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) Unplanned 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) Unplanned Outages: Trouble Report Acknowledgement (T2)

This transaction set:

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

(48) Unplanned Outages: Outage Status Response (T3)

This transaction set:

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

(49) Unplanned 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 Trouble Reporting Request transaction.

19.3.2 Additional SET Transactions

The appropriate TAC subcommittee, or its designated working group, will develop additional transactions as required.

19.4 Texas SET Change Control Documentation

19.4.1 ERCOT TAC Subcommittee Responsibilities

The appropriate ERCOT TAC subcommittee, or its designated working group, will continue to:

(1) Upgrade the standards as needed (based on ideas from MPs, changes to the Protocols or changes in communication standards e.g. changes in ANSI ASC X12 standards), and

(2) Coordinate timing for changes in any of the TX SET transactions.

19.4.2 ERCOT Responsibilities

ERCOT will facilitate the activities listed in Section 19.4, Texas SET Change Control Documentation, by overseeing the change control activities of the TX SET transactions.

19.4.3 Dispute Process

A Market Participant may dispute technical requirement(s) identified in the TX SET Implementation Guide by registering the dispute with ERCOT and the appropriate subcommittee or working group.

19.4.4 Change Control Process

The appropriate TAC subcommittee, or its designated working group, shall make modifications and additions to TX SET transactions in accordance with this Section. TX SET transactions will be expanded and modified to accommodate market or regulatory requirements on an ongoing basis. It is understood that change control is vital in order to allow the market to function successfully on a daily basis. Each MP will rely on established, documented, and tested transactions, yet must have a process by which to modify, test, and implement changes in an efficient, effective, timely, and well-coordinated manner. This change control document provides the process by which changes to the standards may be discussed, reviewed, accepted, and implemented.

19.4.5 Responsibilities of TAC Subcommittee

In order to accommodate the change control process, ERCOT in conjunction with the appropriate TAC subcommittee, or its designated working group, will maintain, publish, and post the standards and the ongoing modifications/enhancements to these standards on the MIS. A consolidated new release of the standards will be published and electronically posted based on the nature and priority of changes requested. The consolidated new release publication will encompass all changes implemented during the period subsequent to the last released publication and will be posted to the MIS.

19.4.6 Submission of Proposed Changes

An Entity proposing a change shall notify ERCOT and/or the TAC subcommittee/designated working group chairperson(s). ERCOT will notify MPs of any change requests. MPs may participate in ERCOT sponsored change control discussions. The TAC subcommittee/designated working group will review and develop a resolution to the change/modification and publish the results. ERCOT will then notify the Entity proposing the change/modification of the results.

19.4.7 Priority Classifications of Standard Electronic Transaction Changes

The appropriate TAC subcommittee, or it's /designated working group, will classify all proposed changes and enhancements in one of the following two categories:

19.4.7.1 Emergency Change Request

Changes/enhancements to the guidelines must be updated as soon as reasonably practicable. If the current standards cannot accommodate Customer choice and an urgent modification of the standard is required, the appropriate TAC subcommittee, or its designated working group, will classify a requested change as an emergency change.

19.4.7.2 Non-Emergency Change Request

Changes/enhancements to the guidelines must be updated by the next release following adoption. If the suggested modifications/enhancements will address immediate regulatory and competitive market issues and mandates, but do not meet the requirements for emergency change, the appropriate TAC subcommittee, or its designated working group, will classify a requested change as non-emergency. Non-emergency may be implemented with a redline to the guideline if it does not affect production.

19.5 Texas SET Acceptable Extended Character Set

19.5.1 Alphanumeric Field(s)

For use on an alphanumeric field, TX SET recognizes all characters within the basic character set. Within the extended character set, TX SET recognizes all character sets except all select language characters found in Section (4) of X-12 Standards Application. Segment/data element gray box guidelines for alphanumeric fields take priority over ANSI standards where the TX SET guidelines further limit acceptable values for a segment/data element. TX SET guidelines cannot extend the acceptable values to characters that are not allowed by ANSI standards for a segment/data element.

19.6 Texas SET Envelope Standards

19.6.1 ERCOT Validation

ERCOT acts as the certificate authority and generates a digital certificate on behalf of each Market Participant (MP). The MP must be identified uniquely within the ERCOT System.

[PRR766: Insert Section 19.7 upon system implementation:]

19.7 Advanced Meter Interval Data Format and Submission

Transmission and/or Distribution Service Providers (TDSPs) will provide 15-minute interval data to ERCOT from provisioned Advanced Meters using an ERCOT specified file format submitted via North American Energy Standards Board (NAESB) on at least a monthly basis.

ERCOT Protocols
Section 20: Alternative Dispute Resolution Procedure

October 1, 2004

20 ALTERNATIVE DISPUTE RESOLUTION PROCEDURE

20.1 Applicability

Except as provided in this Section 20.1, Applicability, this Alternative Dispute Resolution Procedure ("ADR Procedure") shall apply to all disputes between ERCOT and one or more Market Participants or between two or more Market Participants relating to the application, implementation, and interpretation of, or compliance with, these Protocols, any other approved market guide, or related Agreements. ERCOT need not participate as a party or facilitator in the ADR Procedure if none of the parties involved in the ADR Procedure. If any party in the ADR Procedure requests that ERCOT facilitate a dispute, then ERCOT shall do so. The submission of a covered dispute to these ADR Procedures is a condition precedent to any right of any legal action on the dispute. This ADR Procedure is of general applicability.

When an Agreement or a Protocol Section sets forth a specific dispute resolution procedure, the provisions of this Section shall apply only if the dispute remains unresolved after the specific dispute resolution procedures have been exhausted.

Except in the case of a disagreement involving a variance that has been filed through the ERCOT retail transaction issue resolution system or other ERCOT data discrepancy tracking method ("Variance Process"), if the requested outcome of the ADR process involves the correction of settlement data and resettlement by ERCOT pursuant to Section 9, Settlement and Billing, prior to requesting ADR a Market Participant must comply with Section 9.5, Settlement and Billing Dispute Process. If the Market Participant does not comply with Section 9.5, then the Market Participant shall have waived the right to file a complaint regarding the Settlement Statement and ERCOT shall reject the ADR request without further action. Statement Recipients and Invoice Recipients are the only parties that may request the use of ADR where the requested relief would involve correction of settlement data at ERCOT and resettlement by ERCOT pursuant to Section 9, Settlement and Billing, except where the disagreement involves a variance that has been filed through the Variance Process.

This Section shall apply to disagreements involving variances that are filed through a Variance Process. The filing party must have previously complied with all requirements of a Variance Process and submitted the initial variance by the deadline specified in the Variance Process. A request for ADR relating to such a disagreement may seek the correction of the settlement data and resettlement by ERCOT pursuant to Section 9. A party requesting ADR in connection with a Variance Process need not have filed a settlement and billing dispute pursuant to Section 9.5 in order to request and, if appropriate, receive resettlement through the ADR process.

The procedures in this Section do not apply to disputes for which the sole remedy requires a change to the Protocols or related Agreements. The forum for such disputes is the appropriate change or amendment procedure(s) found in Section 21, Process for Protocols Revision.

Nothing in this ADR Procedure is intended to limit or restrict:

(1) The rights of any party to file a complaint with the PUCT or any other Governmental Authority, with respect to matters other than those specified in this Section;

(2) The right of ERCOT or any Market Participant to seek changes in rates or terms and conditions of services, or guidelines, criteria, Protocols, standards, policies, or procedures of ERCOT; or

(3) The right of a Market Participant or ERCOT to file a petition seeking direct relief from the PUCT or any other Governmental Authority without first utilizing this ADR Procedure where an action by ERCOT or a Market Participant might inhibit the ability of the affected party to provide continuous and adequate electric service.

The arbitration procedures set forth in subsection 20.5, Arbitration Procedures, shall not apply to any claim that includes for punitive damages as a part of the requested relief. Such a claim may be pursued in the appropriate forum without pursuing the requirements for arbitration procedures contained in Subsection 20.5, Arbitration Procedures.

Except for the provisions of Section 20.1, Applicability, the ADR Procedure may be modified by mutual agreement of the parties.

Parties shall exercise good faith efforts to timely resolve disputes under this Section.

Nothing here is intended to supersede any dispute resolution process mandated by applicable law or regulation.

Unless the parties to the dispute agree otherwise or unless an applicable tariff or law provides otherwise, the ADR Procedure does not apply to disputes between two or more Market Participants who are either:

(1) parties to a bilateral agreement that relates to the subject matter of the dispute; or

(2) governed by tariffs that relate to the subject matter of the dispute.

20.2 Initiation and Pursuit of ADR Process

20.2.1 Requirement for Written Request

In order to initiate the ADR Procedure, a Market Participant must submit a written request for ADR to the General Counsel of ERCOT. ERCOT shall provide Notice to all parties to the dispute within seven (7) Business Days of receipt of the ADR request and shall include the ERCOT ADR number in the notice. For ADR proceedings that involve more than one Market Participant within five (5) Business Days of receipt of Notice from ERCOT, each Market Participant shall provide the name and contact information of a contact point ("Dispute Contact").

The written request shall include the following information:

(1) The name of the disputing entity;

(2) A contact person for the disputing entity and contact information for that person;

(3) A description of the relief sought;

(4) A detailed description of the grounds for the relief and the basis of each claim which must, at a minimum, identify which Protocol Section(s), any other approved market guide, or related Agreement(s) that the application, implementation, interpretation of or compliance with is being challenged; and

(5) A list of all parties involved in the dispute.

In addition to the foregoing requirements, for ADR proceedings involving settlement disputes submitted pursuant to Section 9.5, Settlement and Billing Dispute Process, or for which the Market Participant seeks a monetary resolution, the Market Participant shall include the following additional information:

(1) Operating Day(s) involved in the dispute;

(2) Settlement dispute number; and,

(3) Amount in dispute (*i.e*. the additional compensation requested by the Market Participant).

20.2.2 Deadline for Initiating ADR Procedure

For any ADR Procedure invoked in connection with a settlement and billing dispute submitted pursuant to Section 9.5, Settlement and Billing Disputes, the Market Participant submitting the dispute must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1, Requirement for Written Request) within forty-five (45) days of the date that ERCOT denied the Market Participant's settlement and billing dispute. ERCOT shall post the dispute resolution date on the portion of the MIS used for the processing of disputes.

For any ADR Procedure invoked in connection with a disagreement arising from a Variance Process, the Market Participant submitting the ADR request must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1, Requirement for Written Request) no later than forty-five (45) days after issuance of the True-Up Statement for the applicable Operating Day.

For any ADR Procedure invoked in connection with any other matter that is not subject to Section 20.2.2, the Market Participant submitting the dispute must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1, Requirement for Written Request) within six (6) months of the date on which information giving rise to the ADR request became available to the Market Participant.

20.2.3 Failure to Pursue ADR Procedure

If the Market Participant that requested the ADR fails to diligently pursue its claim, ERCOT shall send a Notification to the Market Participant's Dispute Contact setting forth a deadline within which the Market Participant must respond in order to preserve its rights. The deadline shall be no less than fifteen (15) days from the date ERCOT sends the Notification. If the Market Participant fails to timely respond to two (2) such Notifications by ERCOT, the Market Participant will be deemed to have waived its rights and the ADR shall be deemed closed. An affirmative statement in writing (including e-mail) that the Market Participant intends to pursue the ADR and a recommended course of action, including a proposed timeline, shall preserve the Market Participant's rights.

20.3 Informal Dispute Resolution

Any dispute subject to ADR as described in this Section shall first 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 and administer the resolution (through delegation or otherwise). Such representatives shall make a good faith effort to resolve the dispute informally as promptly as practicable.

If the senior dispute representatives cannot resolve the dispute by mutual agreement within sixty (60) days of the date on which they take part in a meeting, then the dispute shall be referred to either:

(1) mediation on the request of any party pursuant to Section 20.4; or

(2) arbitration on agreement of all parties pursuant to Section 20.5.

When ERCOT is a party to the dispute and the parties waive the mediation and arbitration procedures by written agreement, the time periods for appeal of the ADR that are set forth in the applicable PUCT regulations shall apply from the date of the meeting between the senior representatives.

20.4 Mediation Procedures

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 (10) days of the request of any party to mediate, then the Commercial Mediation Rules of the American Arbitration Association ("AAA") will be used to select the mediator.

The mediator and representatives of the disputing parties with authority to settle the dispute shall commence mediation of the dispute within fifteen (15) 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. The mediator shall have no authority to impose a resolution on the parties. If the parties have not resolved the dispute within sixty (60) days of the first meeting with the mediator, such parties shall be deemed to be at impasse and the dispute may be submitted to arbitration on agreement of all parties. If such agreement regarding submission to arbitration cannot be reached, any of the parties may apply for relief to the PUCT, or any other Governmental Authority.

20.5 Arbitration Procedures

20.5.1 Initiation of Arbitration

If all the parties have agreed to arbitrate as provided in this Section, any party to the dispute may initiate arbitration by serving a Notice of arbitration, by first class mail certified with return receipt requested, courier service or facsimile, on the other party or parties to the dispute. The Notice of arbitration shall include (1) a statement of claims, (2) a description of the relief sought, (3) a brief summary of grounds for relief and basis of each claim, (4) a list of all parties involved in the dispute, and (5) a description of the good faith efforts made to resolve the dispute under the informal dispute resolution procedures under this Section. Even if ERCOT is not a party to the dispute, a copy of the Notice of arbitration shall be served on the General Counsel of ERCOT. Arbitration proceedings shall be deemed to commence on the date on which the notice of arbitration is received by the non-filing parties.

Each non-filing party shall file a response to the statement of the claim, and shall submit any counterclaims, within ten (10) days of receiving the Notice of arbitration. The responses and any counterclaims shall be served on the General Counsel of ERCOT and all parties to the arbitration.

20.5.2 Selection of Arbitrators

Within seven (7) days after the response to the statement of the claim is filed, the parties to the arbitration shall meet to discuss the selection of an arbitrator.

Arbitration shall, if possible, be conducted before a single neutral arbitrator appointed by the parties. If the parties fail to agree on a single arbitrator within seven (7) days of their initial meeting, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. If there are more than two parties to the dispute, the parties filing the Notice of arbitration shall jointly select one arbitrator and the non-filing parties shall select another. The two arbitrators so chosen shall within seven (7) days select a third arbitrator to chair the arbitration panel. If the two arbitrators are unable to agree on a third arbitrator to chair the panel, the two arbitrators shall be dismissed, and the parties shall each appoint a replacement, and the two replacement arbitrators shall within seven (7) days select a third arbitrator to chair the panel.

Arbitrators shall have no past or current official, financial, or personal conflict of interest with respect to the issues in dispute or parties, unless the interest is fully disclosed in writing to all participants and all participants waive in writing any objection to the conflict of interest.

No party shall have any ex-parte communication with an arbitrator or proposed arbitrator subsequent to the time such person is proposed as an arbitrator and prior to completion of the arbitration process.

20.5.3 Intervention

As soon as practicable after appointment of the arbitrator or the arbitration panel, the arbitrators shall submit to the General Counsel of ERCOT a summary of the dispute (which summary shall not include information claimed to be confidential, proprietary, or Customer-specific), which ERCOT shall post to the MIS. The summary by the arbitrators shall also specify a date for filing of interventions.

An Entity seeking intervention must demonstrate that its rights or interests would be materially affected by the outcome of the arbitration and that it is subject to such outcome, and that it is subject to comparable facts and circumstances to those in dispute. Each party shall have an opportunity to respond to intervention requests. The arbitrators shall have full authority to grant, deny, or condition requests for intervention, including conferring party status on an Entity.

Any Entity seeking to intervene in arbitration, must agree to be bound by the dispute resolution procedures of this section and by the decision of the arbitrators, or of any tribunal to which the decision is appealed, to the same extent as the parties to the arbitration. Intervenors shall share in the costs of the arbitration to the same extent as the other parties to the arbitration.

20.5.4 Conduct of Arbitration

Except as otherwise provided herein, the arbitrators have full discretion over the conduct of hearings, briefing, scheduling, discovery, and other procedural matters. The arbitrators shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the AAA Commercial Arbitration Rules and any applicable rules and regulations of the PUCT or any other tribunal having jurisdiction. In the event of a conflict between the AAA Commercial Arbitration Rules and rules and regulations of the PUCT or any other Governmental Authority, the rules and regulations of the PUCT or any other Governmental Authority having appropriate jurisdiction shall control. In the event of a conflict between the AAA Commercial Arbitration Rules and this ADR Procedure, the procedures set forth in this Section shall control. In addition:

(1) The arbitrators shall allow reasonable opportunity for discovery.

(2) In conducting hearings, the arbitrators shall apply the rules of evidence (including claims of privilege) to the same extent as such rules would be applied by the PUCT or any other Governmental Authority.

(3) To the extent permitted by law, the arbitrators shall take appropriate actions to preserve the confidentiality of information claimed by a party to be confidential, proprietary or Customer-specific.

20.5.5 Arbitration Decisions

The arbitrators shall be authorized only to interpret and apply the provisions of applicable statutory authority (including but not limited to PURA or the FPA), applicable rules, regulations and policies of regulatory authorities having jurisdiction (the PUCT or any other Governmental Authority), and these Protocols and related Agreements, and shall have no power to modify or change any of the foregoing.

Within one hundred and twenty (120) days of appointment, the arbitrators shall render a final decision resolving the dispute. Such decision shall be based on the evidence in the record, the terms of the relevant Agreements and these Protocols, applicable statutes (including but not limited to PURA or the FPA), and applicable rules, regulations, and policies of the regulatory authority having jurisdiction (the PUCT or any other Governmental Authority). Such decision shall be in writing and shall provide the reasons therefore. The arbitrators may agree with the positions of one or more parties or may adopt a different resolution. The arbitrator shall not have authority to grant punitive damages. If the decision is not rendered within one hundred and twenty (120) days of appointment, the arbitrators shall forfeit their fee and any of the parties may apply for relief to the PUCT or any other Governmental Authority having jurisdiction or to any court of competent jurisdiction.

If the decision of the arbitrators is not timely appealed as provided in Section 20.5.6, Appeal of Arbitration Decision, the decision shall be final and binding on the parties. The parties shall take whatever action is required to comply with the decision, and judgment on the decision may be entered and enforced in any court having jurisdiction. Unless appealed, the final decision is binding precedent on the parties and intervenors with respect to the subject matter of the dispute, but is otherwise of no precedential force or effect.

20.5.6 Appeal of Arbitration Decision

Any party to an arbitration under this Section may appeal an arbitration decision to the applicable authority (the PUCT or any Governmental Authority) by providing written notice to that effect to all other parties and intervenors in the arbitration, the arbitrators, ERCOT (if not otherwise served), and the applicable regulatory authority, no later than thirty (30) days following the date the arbitration decision is issued.

A party to arbitration under this Section may appeal the decision of the arbitrators only on the following grounds:

(1) An arbitrator failed to disclose a conflict of interest with one or more of the parties to the dispute, and the decision is substantially biased as a result of the undisclosed conflict;

(2) The decision is inconsistent with, or beyond the scope of, the relevant Agreements or these Protocols; or

(3) The decision is unjust, unreasonable, unduly discriminatory or preferential, or otherwise inconsistent with applicable statutes or with applicable rules, regulations and policies of the authority having jurisdiction (the PUCT or any other Governmental Authority).

Any appeal of an arbitration decision shall be based solely on the record assembled by the arbitrators, unless all parties to the dispute agree in writing to reopen the record for a specified purpose. ERCOT and Market Participants intend that in any appeal, the applicable regulatory authority should accord substantial deference to the factual findings of the arbitrators.

During the pendency of an appeal, the effect of the arbitration decision shall be stayed, unless the disputing parties otherwise agree.

Agreement to these appellate review procedures shall be a precondition for intervention by an Entity other than ERCOT or a Market Participant in an arbitration proceeding under this Section.

20.6 Dispute Resolution Costs

Each party shall be responsible for its own costs incurred during this ADR Procedure and for a pro rata share of the cost of the mediator or arbitrators. The pro rata share will be based on the number of parties.

The arbitrators may impose costs against an offending party if the arbitrators conclude that the party has abused this ADR Procedure.

20.7 Requests for Data

If, as part of the ADR Procedure, a party requests documents or data from another party to the ADR, the responding party must provide either:

(1) the requested documents or data to the requesting party within fifteen (15) days of the request;

(2) an explanation of why the party believes the documents or data should not be produced (*e.g.* relevance); or,

(3) 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.

Additionally, if the ADR proceeds to mediation or arbitration, a party may request that arbitrator or mediator decide if documents or data are relevant to the ADR and, if it is relevant to the ADR, the document or data must be provided by the other party within a timeframe specified by the mediator or arbitrator.

ERCOT and Market Participants will protect from public disclosure any and all Protected Information provided in response to the ADR Procedure pursuant to a mutually agreeable confidentiality agreement.

All information provided pursuant to this subsection may be provided by mail, facsimile, or other electronic communications.

20.8 Resolution of Disputes and Notification to Market Participants

Upon resolution of an ADR claim, ERCOT and/or the Market Participants must enter into a written dispute resolution agreement disposing of the Market Participant's claim.

ERCOT shall send a Notification of the negotiated settlement amount and the manner in which the resulting overpayments or underpayments will be allocated to the appropriate Settlement Statement and Invoice Recipients, including the specific Settlement Statements and Settlement Invoices that will be affected. The Notification shall provide details including, but not limited to, the Operating Day, service type, total amount of the adjustment to the market and total adjustment to the Invoice Recipient.

In the event a determination is made that there has been an error in ERCOT's processes, procedures, or systems that resulted in overpayments or underpayments to one or more Market Participants, the Chief Executive Officer of ERCOT may negotiate a resolution to a dispute arising from such error in a manner that deviates from the normal application of the Protocols in order to settle the dispute under this ADR Procedure with the approval of the ERCOT Board of Directors. These occurrences will be subject to the requirements of Section 9.2.5.1, Notice of Resettlement.

20.9 Settlement of Approved ADR Claims

20.9.1 Adjustments Based on ADR Resolution

If Resettlement is possible to address an adjustment required by an ADR resolution, ERCOT shall issue a Resettlement Statement for the affected Operating Day(s) and shall adjust applicable timelines accordingly.

If a resettlement is not practical or possible to address an adjustment required by an ADR resolution, ERCOT shall make the adjustments through a separate "ADR Invoice" that is produced outside of the normal settlement system. The appropriate payments and charges, along with settlement quality information, shall be supplied to all Market Participants. Any dispute resolution amount greater than five million dollars ($5,000,000) shall be divided so that no one ADR Invoice has more than five million dollars ($5,000,000) in ADR adjustments and such ADR Invoices shall be issued at least fourteen (14) days apart from each other. Payments will be due on the date specified on the ADR Invoice. Any short and late payments will be handled pursuant to Section 9.4.4, Partial Payments and 9.4.6, Late Fees respectively.

20.9.2 Charges for Approved ADR Claim

The charges assigned to Market Participants to pay for an approved ADR claim will be settled on the same Settlement Statement as set forth in Section 20.9.1, Adjustments Based on ADR Resolutions. ERCOT will assign the costs for the approved ADR claim according to the appropriate allocation for the market service in dispute as outlined in Section 6.9, Settlement for ERCOT-Provided Ancillary Services; Section 7.4, Congestion Management for Local

Congestion; and, other Protocol Sections as appropriate. Charges that are necessary relating to other types of dispute resolution will be made in pursuant to the directives of the Protocols.

ERCOT Protocols
Section 21: Process for Protocol Revision

May 1, 2009

21 PROCESS FOR PROTOCOL REVISION

21.1 Introduction

A request to make additions, edits, deletions, revisions, or clarifications to these Protocols, including any attachments and exhibits to these Protocols, is called a "Protocol Revision Request" (PRR). Except as specifically provided otherwise in the following sentence or in other Sections of these Protocols, Sections 21.2 through 21.10 apply to all PRRs. Section 21.11 applies to requests to make additions, edits, deletions, revisions, or clarifications to the Protocols developed pursuant to P.U.C. SUBST. R. 25.501 (Wholesale Market Design in ERCOT) to implement the Texas nodal market redesign (Nodal Protocols) until the date of full implementation of Texas nodal market. ERCOT Members, Market Participants, PUCT staff, ERCOT staff, 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.

All decisions of the Protocol Revision Subcommittee (PRS), as defined below, the ERCOT Technical Advisory Committee (TAC) and the ERCOT Board (Board) with respect to any PRR shall be posted to the MIS within three (3) Business Days of the date of the decision. All such postings shall be maintained on the MIS for at least one hundred eighty (180) days from the date of posting.

The "next regularly scheduled meeting" of the Protocol Revision Subcommittee, TAC or the 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 Board or committee procedures.

21.2 Submission of a Protocol Revision Request

The following Entities may submit a PRR:

(1) Any Market Participant;

(2) Any Entity that is an ERCOT Member;

(3) PUCT Staff;

(4) ERCOT Staff; and

(5) Any other Entity that meets the following qualifications:

(a) Entity must reside (or represent residents) in Texas or operate in the Texas electricity market, and

(b) Entity must demonstrate that Entity (or those it represents) is affected by the Customer Registration or REC Program Sections of these Protocols.

21.3 Protocol Revision Subcommittee

TAC shall assign a subcommittee ("Protocol Revisions Subcommittee" or “PRS”) to review and recommend action on formally submitted PRRs. TAC may create such a subcommittee or assign the responsibility to an existing subcommittee, provided that:

(1) such subcommittee’s meetings are open to ERCOT Staff, ERCOT Members, Market Participants, and the PUCT Staff;

(2) each Market Segment is allowed to participate; and

(3) each Market Segment has equal voting power.

Where additional expertise is needed, the PRS may refer a PRR to working groups or task forces that it creates or to existing subcommittees, working groups or task forces of TAC for review and comment on the PRR. Suggested modifications—or alternative modifications if a consensus recommendation is not achieved by a non-voting working group or task force—to the PRR 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 PRR for consideration by PRS. However, the PRS shall retain ultimate responsibility for the processing of all PRRs.

ERCOT shall consult with the chair of the PRS to coordinate and establish the meeting schedule for the PRS or other assigned subcommittee. 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 to the MIS.

21.4 Protocol Revision Procedure

21.4.1 Review and Posting of Protocol Revision Requests

PRRs shall be submitted electronically to ERCOT by completing the designated form provided on the MIS. ERCOT shall provide an electronic return receipt response to the submitter upon receipt of the PRR.

The PRR shall include the following information:

(1) description of requested revision;

(2) reason for the suggested change;

(3) 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;

(4) PRR Impact Analysis (PIA) (applicable only for a PRR submitted by ERCOT Staff);

(5) list of affected Protocol Sections and subsections;

(6) general administrative information (organization, contact name, etc.); and

(7) suggested language for requested revision.

ERCOT shall evaluate the PRR for completeness and shall notify the submitter, within five (5) Business Days of receipt, if the PRR is incomplete, including the reasons for such status. ERCOT may provide information to the submitter that will correct the PRR and render it complete. An incomplete PRR shall not receive further consideration until it is completed. In order to pursue the revision requested, a submitter must submit a completed version of the PRR with the deficiencies corrected.

If a submitted PRR is complete or once a PRR is corrected, ERCOT shall post a complete PRR to the MIS and distribute the PRR to the PRS within three (3) Business Days.

21.4.2 Withdrawal of a Protocol Revision Request

Upon notice to the PRS, the submitter of a PRR may withdraw the PRR at any time prior to approval of the PRR by the PRS. ERCOT shall post a notice of the submitter's withdrawal of a PRR on the MIS within one (1) Business Day of the submitter's notice to PRS.

The submitter of a PRR may request withdrawal of a PRR after its approval by PRS. Such withdrawal must be approved by the TAC (if it has not yet been considered by TAC) or by the Board (if it has been recommended for Board approval by TAC but not yet considered by the Board).

Once approved by the Board a PRR cannot be withdrawn.

21.4.3 Protocol Revision Subcommittee Review and Action

Any interested ERCOT Member, Market Participant, the PUCT Staff, Texas Regional Entity (TRE) Staff or ERCOT Staff may comment on the PRR.

To receive consideration, comments must be delivered electronically to ERCOT in the designated format provided on the MIS within twenty-one (21) days from the posting date of the PRR. Comments submitted after the due date of the twenty-one (21) 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 MIS—regardless of date of submission—shall be posted to the MIS and distributed electronically to the PRS within three (3) Business Days of submittal.

The PRS shall review the PRR at its next regularly scheduled meeting after the end of the twenty-one (21) day comment period, unless the twenty-one (21) day comment period ends less than three (3) Business Days prior to the next regularly scheduled PRS meeting. In that case, the

PRR will be reviewed at the following month's regularly scheduled PRS meeting. At such meeting, the PRS may take action on the PRR. The quorum and voting requirements for PRS action are set forth in the Technical Advisory Committee Procedures. In considering action on a PRR, PRS may:

(1) recommend approval of the PRR as submitted or as modified;

(2) reject the PRR;

(3) defer decision on the PRR; or

(4) refer the PRR to a subcommittee, workgroup, or task force as provided in Section 21.3, Protocol Revision Subcommittee.

If a motion is made to recommend approval of a PRR and that motion fails, the PRR shall be deemed rejected by PRS unless at the same meeting PRS later votes to recommend approval of or refer the PRR. The rejected PRR shall be subject to appeal pursuant to Section 21.4.11.1, Appeal of PRS Action.

Within three (3) Business Days after PRS takes action to approve, approve with modifications, or reject the PRR, ERCOT shall issue a report ("PRS Recommendation Report") to TAC reflecting the PRS action and post the same to the MIS. The PRS Recommendation Report shall contain the following items:

(1) identification of submitter;

(2) modified Protocol language proposed by the PRS;

(3) identification of authorship of comments;

(4) proposed effective date(s) of the PRR;

(5) priority and rank for any PRRs requiring a system change project; and

(6) recommended action: approval or approval with modified language.

The PRS chair shall notify TAC of PRRs rejected by PRS.

21.4.4 Comments to the Protocol Revision Subcommittee Recommendation Report

Any interested ERCOT Member, Market Participant, PUCT Staff, TRE Staff or ERCOT Staff may comment on the PRS Recommendation Report. To receive consideration, comments on the PRS Recommendation Report must be delivered electronically to TAC and ERCOT in the designated format provided on the MIS within twenty-one (21) days from the date of posting/distribution of the PRS Recommendation Report. Comments submitted after the due date of the twenty-one (21) day comment period may be considered at the discretion of TAC.

Within three (3) Business Days of receipt of comments related to the PRS Recommendation Report, ERCOT shall post such comments to the MIS. The comments shall include identification of the commenting Entity.

Comments submitted in accordance with the instructions on the MIS—regardless of date of submission—shall be posted to the MIS and distributed electronically to the TAC and PRS within three (3) Business Days of submittal.

TAC shall review the PRS Recommendation Report and any posted comments to the Report at its next regularly scheduled meeting after the end of the twenty-one (21) day comment period, unless the twenty-one (21) day comment period ends less than seven (7) days prior to the next regularly scheduled TAC meeting. In that case, the PRR will be reviewed at the following month's regularly scheduled TAC meeting.

21.4.5 Protocol Revision Request Impact Analysis

ERCOT shall submit an initial PIA with any PRR ERCOT submits to the PRS based on the original language in the PRR. The Initial PIA will provide PRS with guidance as to what computer systems, operations, or business functions could be affected by the PRR as submitted.

The PIA should assess the impact of the proposed PRR on ERCOT computer systems, operations, or business functions and shall contain the following information:

(1) an estimate of any cost and budgetary impacts to ERCOT for both implementation and on-going operations;

(2) the estimated amount of time required to implement the revised Protocol language;

(3) the identification of alternatives to the original proposed language that may result in more efficient implementation;

(4) the identification of any manual workarounds that may be used as an interim solution and estimated costs of the workaround; and

(5) verification of review (if necessary) of the PRR by the Credit Working Group and the impact of its review on the PIA.

Upon receipt of a PRR submitted by any Entity other than ERCOT, ERCOT shall perform an initial evaluation of the impact on ERCOT and include the evaluation in ERCOT's comments. The initial evaluation will provide PRS with guidance as to what computer systems, operations, or business functions could be affected by the PRR as submitted. ERCOT shall post its comments prior to the PRS initial review of the PRR, if practicable.

After the PRS's initial review and recommendation of approval of a PRR, and the issuance and posting of the PRS Recommendation Report, ERCOT shall prepare a PIA based on the PRS Recommendation Report to identify and evaluate the required changes to the ERCOT Systems and staffing needs, including, but not limited to, ERCOT's operating systems, settlement systems, business functions, operating practices, ERCOT System operations, and staffing needs. If ERCOT has already prepared a PIA, then ERCOT shall instead update the existing PIA, if needed, to accommodate the PRS Recommendation Report.

Unless a longer review period is warranted due to the complexity of the proposed PRS Recommendation Report, ERCOT shall issue the PIA for the recommended PRR within twenty-five (25) days after PRS approval of the PRR. ERCOT shall post the results of the completed PIA on the MIS. If a longer review period is required for ERCOT Staff to complete a full PIA, ERCOT Staff shall submit a schedule for completion of the PIA to the PRS chair.

21.4.6 Protocol Revision Subcommittee Review of Impact Analysis

After ERCOT posts the results of the PIA, PRS shall review the PIA at its next regularly scheduled meeting. PRS may revise its PRS Recommendation Report after considering the information included in the PIA.

If PRS revises its Recommendation Report, a revised PRS Recommendation Report shall be issued by PRS to TAC and posted on the MIS. Additional comments received regarding the revised PRS Recommendation Report shall be accepted up to three (3) Business Days prior to the TAC meeting at which the PRR is scheduled for consideration. If PRS revises its recommendation, ERCOT shall update the PIA and issue the updated PIA at least three (3) Business Days prior to the regularly scheduled TAC meeting. If a longer review period is required for ERCOT to update the PIA, ERCOT shall submit a schedule for completion of the PIA to the TAC chair.

After consideration of the final PIA and PRS Recommendation Report (and any revisions made), and if the PRR would require an ERCOT project for implementation, at the same meeting PRS shall assign a priority and ranking for the associated project.

21.4.7 Technical Advisory Committee Vote

TAC shall consider any PRRs that PRS has submitted to TAC for consideration for which both a PRS Recommendation Report has been posted and a PIA based on such PRS recommendation (as updated if modified by PRS under Section 21.4.6, Protocol Revision Subcommittee Review of Impact Analysis) has been posted on the MIS for at least three (3) days. The following information must be included for each PRR considered by TAC:

(1) the PRS Recommendation Report and PIA;

(2) the recommended PRS priority and ranking if an ERCOT project is required; and

(3) any comments timely received in response to the PRS Recommendation Report.

The quorum and voting requirements for TAC action are set forth in the Technical Advisory Committee Procedures. In considering action on a PRS Recommendation Report, TAC shall:

(1) recommend approval of the PRR as recommended in the PRS Recommendation Report or as modified by TAC including modification of the recommended priority and ranking if the PRR requires a project;

(2) reject the PRR;

(3) defer decision on the PRR;(4)remand the PRR to the PRS with instructions; or

(5) refer the PRR to another TAC subcommittee or a TAC working group or task force with instructions.

If a motion is made to recommend approval of a PRR and that motion fails, the PRR shall be deemed rejected by TAC unless at the same meeting TAC later votes to recommend approval of, remand, or refer the PRR. The rejected PRR shall be subject to appeal pursuant to Section 21.4.11.2, Appeal of TAC Action.

If TAC recommends approval of a PRR that does not require an ERCOT project for implementation or requires an ERCOT project which can be performed in the current ERCOT budget cycle based upon its priority and ranking, ERCOT shall prepare a TAC Recommendation Report, issue the report to the ERCOT Board and post the report on the MIS within three (3) Business Days of the TAC recommendation concerning the PRR. The TAC Recommendation Report shall contain the following items:

(1) identification of the submitter of the PRR;

(2) modified Protocol language proposed by TAC;

(3) identification of the authorship of comments;

(4) proposed effective date(s) of the PRR;

(5) priority and rank for any PRR requiring a system change request;

(6) PRS recommendation; and

(7) TAC recommendation.

If TAC recommends approval of a PRR that requires a project for implementation that cannot be funded within the current ERCOT budget cycle, ERCOT shall prepare a TAC Recommendation Report and post the report on the MIS within three (3) Business Days of the TAC recommendation concerning the PRR. ERCOT shall assign the approved PRR to the “Unfunded Project List” until the ERCOT Board approves an annual ERCOT budget in a manner that indicates funding would be available in the new budget cycle to implement the project if approved by the ERCOT Board; in such case, the TAC Recommendation Report would be provided at the next ERCOT Board meeting following such budget approval for the ERCOT Board's consideration under Section 21.4.9, ERCOT Board Vote.

Notwithstanding the above, a PRR on the Unfunded Project List may be removed from the list and provided to the ERCOT Board for approval, as set forth in Section 21.9, Review of Project Prioritization, Review of Unfunded Project List, and Annual Budget Process.

ERCOT shall maintain the Unfunded Project List to track projects that cannot be funded in the current ERCOT budget cycle.

Any PRR approved by TAC but assigned to the Unfunded Project List may be challenged by appeal as otherwise set forth in this Section.

21.4.8 ERCOT Impact Analysis Based on Technical Advisory Committee Recommendation Report

For PRRs not designated Urgent, ERCOT shall review the TAC Recommendation Report and update the PIA as soon as practicable, but no later than thirty (30) days after the TAC Recommendation Report is issued, unless a longer period is warranted due to the complexity of the changes proposed by TAC. If the PRR does not require a project assigned to the Unfunded Project List, ERCOT shall issue the updated PIA (if any) to the ERCOT Board and post it on the MIS within three (3) Business Days of issuance. If a longer review period is required for ERCOT Staff to update the PIA, ERCOT Staff shall submit a schedule for completion of the PIA to the TAC and ERCOT Board chairs.

For PRRs designated Urgent, ERCOT shall prepare the PIA within thirty (30) days after the TAC Recommendation Report is issued or based on a TAC approved accelerated schedule, unless a longer period is warranted due to the complexity of the changes proposed by TAC. If the PRR does not require a project assigned to the Unfunded Project List, ERCOT shall issue the PIA to the ERCOT Board and post it on the MIS. If a longer review period is required for ERCOT Staff to update the PIA, ERCOT Staff shall submit a schedule for completion of the PIA to the TAC and ERCOT Board chairs.

21.4.9 ERCOT Board Vote

Upon approval of a PRR by the TAC and issuance of a PIA by ERCOT to the ERCOT Board, the ERCOT Board shall review the TAC Recommendation Report and the PIA at its next regularly scheduled meeting; provided that the PIA is available for distribution to the ERCOT Board at least eleven (11) days in advance of the ERCOT Board meeting.

The quorum and voting requirements for ERCOT Board action are as set forth in the ERCOT Bylaws. In considering action on a TAC Recommendation Report, the ERCOT Board shall:

(1) approve the TAC Recommendation Report as originally submitted or as modified by the ERCOT Board;

(2) reject the TAC Recommendation Report;

(3) defer decision on the merits of the TAC Recommendation Report; or

(4) remand the TAC Recommendation Report to TAC with instructions.

If a motion is made to approve a TAC Recommendation Report and that motion fails, the PRR shall be deemed rejected by the ERCOT Board unless at the same meeting the ERCOT Board later votes to approve or remand the TAC Recommendation Report. The rejected PRR shall be subject to appeal pursuant to Section 21.4.11.3, Appeal of ERCOT Board Action.

If the TAC Recommendation Report is approved by the ERCOT Board, as recommended by TAC or as modified by the ERCOT Board, the ERCOT Board shall review and approve or modify the proposed effective date.

21.4.10 Posting of ERCOT Board Action and Filing of Approved Protocol Modification

The ERCOT Board's action regarding approval or rejection of a PRR shall be posted on the MIS as a Board Action Report within three (3) Business Days after the ERCOT Board's action.

If the ERCOT Board approves a change or changes to the Protocols, such change(s) shall be:

(1) filed with the PUCT for informational purposes as soon as practicable, but no later than one (1) day before the effective date of the changes; and

(2) incorporated into the Protocols and posted on the MIS as soon as practicable, but no later than one (1) day before the effective date of the changes.

21.4.11 Appeal of Decision

The following processes are to be used to appeal a decision related to a PRR.

21.4.11.1 Appeal of PRS Action

Any ERCOT Member, Market Participant, PUCT Staff or ERCOT Staff may appeal directly to the TAC, any PRS action regarding a PRR. Such appeal to the TAC must be submitted electronically to ERCOT and the TAC Chair by completing the designated form provided on the MIS within ten (10) Business Days after the date of the relevant PRS appealable event. ERCOT shall reject appeals made after that time. ERCOT shall post the appeal on the ERCOT web page dedicated to the TAC and the specific PRR within three (3) Business Days of receiving the appeal. If the appeal is submitted to ERCOT at least eleven (11) days before the next regularly scheduled TAC meeting, ERCOT shall place the appeal on the agenda of the next regularly scheduled TAC meeting. If the appeal is submitted to ERCOT less than eleven (11) days before the next regularly scheduled TAC meeting, the TAC will hear the appeal at the next subsequent regularly scheduled meeting. An appeal of a PRR to TAC suspends consideration of the PRR until the appeal has been decided by TAC.

21.4.11.2 Appeal of TAC Action

Any ERCOT Member, Market Participant, PUCT Staff or ERCOT Staff may appeal directly to the ERCOT Board, any TAC action regarding a PRR. Appeals to the ERCOT Board shall be processed in accordance with the ERCOT Board Policies and Procedures. An appeal of a PRR to the ERCOT Board suspends consideration of the PRR until the appeal has been decided by the ERCOT Board.

21.4.11.3 Appeal of ERCOT Board Action

Any ERCOT Member, Market Participant or PUCT Staff may appeal any decision of the ERCOT Board regarding the PRR 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 thirty-five (35) days of the date of the relevant 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 PRR, ERCOT shall post the ruling on the MIS.

21.5 Urgent Requests

The party submitting a PRR may request that the PRR be considered on an urgent basis ("Urgent") only when the submitter can reasonably show that an existing Protocol 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.

If a submitter requests Urgent status for a PRR, or upon a valid motion in a regularly scheduled meeting of the PRS and the PRS determines that such PRR:

(1) requires immediate attention from TAC due to (a) serious concerns about ERCOT System reliability or market operations under the unmodified language or (b) the crucial nature of settlement activity conducted pursuant to any settlement formula; and

(2) is of a nature that allows for rapid implementation without negative consequence to the reliability and integrity of the ERCOT System or market operations; then

PRS may designate the PRR for Urgent consideration. The PRS shall consider the Urgent PRR at its earliest regularly scheduled meeting, or at a special meeting called by the PRS chair to consider the Urgent PRR.

If approved, ERCOT shall submit an Urgent PRS Recommendation Report to the TAC within three (3) 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.

Notice of an Urgent PRR pursuant to this subsection shall be posted on the MIS. Any revisions to these Protocols that take effect pursuant to an Urgent request shall be subject to an ERCOT PIA pursuant to Section 21.4.8, ERCOT Impact Analysis Based on Technical Advisory Committee Recommendation Report, and ERCOT Board consideration pursuant to Section 21.4.9, ERCOT Board Vote.

21.6 Protocol Revision Implementation

Upon Board approval, ERCOT shall implement PRRs on the first (1st) day of the month following Board approval, unless otherwise provided in the Board Action Report for the approved PRR.

For such other PRRs, ERCOT shall post estimated implementation dates and provide notice as soon as practicable, but no later than ten (10) days prior to actual implementation, unless a different notice period is required in the Board Action Report for the approved Protocol Revision.

21.7 Submission of a System Change Request

A System Change Request (SCR) is a request to make a change to ERCOT's computer systems that does not require a change to the ERCOT Protocols.

The following Entities may submit a System Change Request (SCR):

(1) any Market Participant;

(2) any Entity that is an ERCOT Member;

(3) the PUCT Staff;

(4) any other Entity that meets the following qualifications:

  (a) Entity must reside (or represent residents) in Texas or operate in the Texas electricity market, and

  (b) Entity must demonstrate that Entity (or those it represents) is affected by the Customer Registration or REC Program Sections of these Protocols.

21.8 System Change Request Procedure

21.8.1 Review and Posting of System Change Requests

System Change Requests (SCRs) shall be submitted electronically to ERCOT by completing the designated form provided on the Market Information System (MIS). ERCOT shall provide an electronic return receipt response to the submitter upon receipt of the SCR. All SCRs must include a detailed explanation of the effect to the ERCOT market structure, ERCOT Market Participants, and ERCOT operations.

The SCR shall also include the following information:

(1) description of desired additional system functionality or the additional information desired;

(2) reason for the suggested change;

(3) impacts and benefits of the suggested change to ERCOT operations and Market Participants, to the extent that submitter may know this information; and

(4) general administrative information (organization, contact name, etc.).

ERCOT shall evaluate the SCR to determine whether the request should be submitted as a Protocol Revision Request (PRR) or Nodal Protocol Revision Request (NPRR). If ERCOT determines that the SCR should be submitted as a PRR or NPRR, ERCOT will notify the submitting Entity within five (5) Business Days of receipt, and the submitting Entity shall withdraw its SCR and may submit a PRR or NPRR in its place.

ERCOT shall evaluate the SCR for completeness and shall notify the submitting Entity, within five (5) Business Days of receipt, 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 with the deficiencies corrected.

Any SCR that impacts system functionality for the nodal market must be evaluated by the ERCOT Chief Executive Officer (ERCOT CEO) or his designee before assigning the SCR to the appropriate subcommittee of TAC ("Assigned TAC Subcommittee"). The ERCOT CEO or his designee shall complete his evaluation within five (5) Business Days or provide notice to the submitter that additional time is necessary. Within three (3) Business Days after the ERCOT CEO's or his designee's decision, ERCOT shall notify the submitter of the SCR of the ERCOT CEO's or his designee's determination. If the ERCOT CEO or his designee determines the SCR is not necessary prior to the Texas Nodal Market Implementation Date, any ERCOT Member, Market Participant, Public Utility Commission of Texas (PUCT) Staff or ERCOT Staff may appeal the decision directly to the ERCOT Board. Such appeal to the ERCOT Board must be submitted to ERCOT within ten (10) Business Days after the date of the ERCOT CEO's or his designee's decision.

Once an SCR that impacts system functionality for the nodal market has been evaluated by the ERCOT CEO or his designee, ERCOT shall post the completed SCR and the ERCOT CEO's or his designee's decision to the MIS and distribute the SCR and the ERCOT CEO's or his designee's decision to the Assigned TAC Subcommittee within three (3) Business Days after the ERCOT CEO's or his designee's decision has been made.

ERCOT shall assign a complete SCR to the Assigned TAC Subcommittee, post the SCR to the MIS and distribute the SCR to the Assigned TAC Subcommittee within three (3) Business Days of a determination of completeness for an SCR that does not impact system functionality for the nodal market or within three (3) Business Days after the ERCOT CEO's or his designee's decision on an SCR that impacts system functionality for the Nodal market. .

Any posted SCR that impacts system functionality for the nodal market and that changes scope during the stakeholder process may need to be further evaluated by the ERCOT CEO or his designee before proceeding to the next TAC subcommittee, TAC or ERCOT Board for review.

21.8.2 Withdrawal of a System Change Request

Upon notice to ERCOT, the submitter of a SCR may withdraw the SCR at any time prior to approval of the SCR by any standing TAC subcommittee.

ERCOT shall post a notice of the submitter's withdrawal of a SCR on the MIS within one (1) Business Day of the submitter's notice to ERCOT.

The submitter of a SCR may request withdrawal of a SCR after its approval by the Assigned TAC Subcommittee. Such withdrawal must be approved by the TAC (if it has not yet been considered by TAC) or by the Board (if it has been recommended for Board approval by TAC but not yet considered by the Board).

Once approved by the Board, an SCR cannot be withdrawn.

21.8.3 Subcommittee Review and Action

Any interested ERCOT Member, Market Participant, the PUCT Staff, Texas Regional Entity (TRE) or ERCOT Staff may comment on the SCR. To receive consideration, comments must be delivered electronically to the Assigned TAC Subcommittee and ERCOT in the designated format provided on the MIS within twenty-one (21) days from the date of posting/distribution of the SCR.

Comments submitted after the due date of the twenty-one (21) day comment period may be considered at the discretion of the Assigned TAC Subcommittee.

Comments submitted in accordance with the instructions on the MIS shall be posted to the MIS—regardless of date of submission—and distributed electronically to the Assigned TAC Subcommittee within three (3) Business Days of submittal.

The Assigned TAC Subcommittee shall review the SCR along with any posted comments at its next regularly scheduled meeting after the end of the twenty-one (21) day comment period, unless the end of the twenty-one (21) day comment period falls within three (3) Business Days of the regularly scheduled meeting of the Assigned TAC Subcommittee. In that case, the SCR shall be reviewed at the next regularly scheduled meeting of the Assigned TAC Subcommittee.

The quorum and voting requirements for TAC subcommittee action are set forth in the Technical Advisory Committee Procedures.

If a motion is made to recommend approval of an SCR and that motion fails, the SCR shall be deemed rejected by the Assigned TAC Subcommittee unless at the same meeting the Assigned TAC Subcommittee later votes to recommend approval of or refer the SCR. The SCR shall be subject to appeal pursuant to Section 21.8.12.1, Appeal of Assigned TAC Subcommittee Action.

Within three (3) Business Days after the Assigned TAC Subcommittee takes action on the SCR, ERCOT shall issue the SCR Recommendation Report to TAC reflecting the Assigned TAC Subcommittee action and post the same to the MIS.

The SCR Recommendation Report shall contain the following items:

(1) identification of submitter;

(2) summary of the requested changes to the ERCOT Systems;

(3) identification of authorship of comments; and

(4) recommended action (e.g., approval, rejection, approval of modified language, etc.)

The Assigned TAC Subcommittee chair shall notify TAC of SCRs recommended by the Assigned TAC Subcommittee chair for rejection.

21.8.4 Comments to the Assigned Subcommittee Recommendation Report

Any interested ERCOT Member, Market Participant, the PUCT Staff, TRE Staff or ERCOT Staff may comment on the SCR Recommendation Report. To receive consideration, comments must be delivered electronically to ERCOT within twenty-one (21) days from the date of posting of the SCR Recommendation Report by completing and submitting the comment form provided on the MIS.

Within three (3) Business Days of receipt of comments related to the SCR Recommendation Report, ERCOT shall post such comments to the MIS. The comments shall include identification of the commenting Entity.

21.8.5 System Change Request Impact Analysis

Upon posting of a SCR, ERCOT shall conduct an initial SCR Impact Analysis (SIA) based on the submitted language. The purpose of the initial SIA is to provide the Assigned TAC Subcommittee with guidance as to what computer systems, operations, or business functions could be affected by the SCR as submitted. ERCOT shall report the initial SIA's results to the Assigned TAC Subcommittee at the meeting when the SCR is discussed.

After the Assigned TAC Subcommittee's initial review and recommendation of approval of a SCR and the issuance and posting of the SCR Recommendation Report, ERCOT shall initiate a SIA based on the SCR Recommendation Report to identify and evaluate the required changes to the ERCOT Systems and staffing needs, including, but not limited to, ERCOT's operating systems, settlement systems, business functions, operating practices, ERCOT System operations, and staffing needs.

The SIA shall include:

(1) an estimate of any cost and budgetary impacts to ERCOT;

(2) the estimated amount of time required to implement the changes to the systems;

(3) the identification of alternatives to the original proposed system requirements that may result in more efficient implementation; and

(4) the identification of any manual workarounds that may be used as an interim solution.

Unless a longer period is warranted due to the complexity of the proposed system changes as indicated in the SCR Recommendation Report, ERCOT shall issue a SIA for the recommended SCR within twenty-five (25) days after approval of the SCR by the Assigned TAC Subcommittee. After the completion of the SIA, ERCOT shall post the results of the SIA on the MIS. If a longer review period is required by the ERCOT Staff to update the SIA, ERCOT Staff shall submit a schedule for completion of the SIA to the Assigned TAC Subcommittee chair.

21.8.6 Assigned TAC Subcommittee Review of SCR Impact Analysis

After ERCOT posts the results of the SIA, the Assigned TAC Subcommittee shall review the SIA at its next regularly scheduled meeting. The Assigned TAC Subcommittee may revise its SCR Recommendation Report after considering the information included in the SIA.

If the Assigned TAC Subcommittee revises its recommendation, ERCOT shall prepare a revised SCR Recommendation Report, issue the report to TAC and post the report on the MIS within three (3) Business Days of the Assigned TAC Subcommittee recommendation concerning this SCR. Additional comments received regarding the revised SCR Recommendation Report will be accepted up to three (3) Business Days prior to the TAC meeting at which the SCR is scheduled for consideration.

ERCOT shall also update the SIA as necessary and issue the updated SIA to TAC at least three (3) Business Days prior to the regularly scheduled TAC meeting. If a longer review period is required for ERCOT Staff to update the SIA, ERCOT Staff shall submit a schedule for completion of the PIA to the TAC chair.

If the SCR requires an ERCOT project for implementation, the SCR will be posted for the next PRS meeting for which proper notice can be given. At such meeting, PRS shall assign a priority and ranking for the associated project. The priority and ranking designation shall be added to the SCR Recommendation Report within three (3) Business Days of the PRS priority and ranking assignment recommendation concerning this SCR.

21.8.7 Technical Advisory Committee Vote

At its next regularly scheduled meeting after receiving the information described below, TAC shall consider:

(1) the SCR Recommendation Report based on the Assigned TAC Subcommittee's review of the SIA;

(2) the recommended PRS priority and ranking if an ERCOT project is required;

(3) comments timely received in response to the SCR Recommendation Report; and

(4) ERCOT's SIA.

TAC shall take one of the following actions regarding the SCR Recommendation Report:

(1) recommend approval of the SCR as recommended in the SCR Recommendation Report or as modified by TAC, including modification of the priority and ranking if the SCR requires a project;

(2) reject the SCR;

(3) defer decision on the SCR; or

(4) remand the SCR to a standing TAC Subcommittee.

The quorum and voting requirements for TAC action are set forth in the Technical Advisory Committee Procedures.

If a motion is made to recommend approval of an SCR and that motion fails, the SCR shall be deemed rejected by TAC unless at the same meeting TAC later votes to recommend approval of, remand or refer the SCR. The rejected SCR shall be subject to appeal pursuant to Section 21.8.12.2, Appeal of TAC Action.

If TAC recommends approval of an SCR that does not require an ERCOT project for implementation or requires an ERCOT project which can be performed in the current ERCOT budget cycle based upon its priority and ranking, ERCOT shall prepare a TAC Recommendation Report, issue the report to the ERCOT Board and post the report on the MIS within three (3) Business Days of the TAC recommendation concerning the SCR. The TAC Recommendation Report shall contain the following items:

(1) identification of the submitter of the SCR;

(2) identification of the authorship of comments;

(3) proposed effective date(s) of the SCR;

(4) priority and rank for any SCRs requiring a system change project; and

(5) TAC recommendation.

If TAC recommends approval of an SCR that requires a project for implementation that cannot be funded within the current ERCOT budget cycle, ERCOT shall prepare a TAC Recommendation Report and post the report on the MIS within three (3) Business Days of the TAC recommendation concerning this SCR. ERCOT shall assign the approved SCR to the Unfunded Project List until the ERCOT Board approves an annual ERCOT budget in a manner that indicates funding would be available in the new budget cycle to implement the project if approved by the ERCOT Board; in such case, the TAC Recommendation Report would be provided at the next ERCOT Board meeting following such budget approval for the ERCOT Board's consideration under Section 21.8.9, ERCOT Board Vote. Any SCR approved by TAC but assigned to the Unfunded Project List may be challenged by appeal as otherwise set forth in this Section.

Notwithstanding the above, an SCR in the Unfunded Project List may be removed from the list and provided to the ERCOT Board for approval, as set forth in Section 21.9, Review of Project Prioritization, Review of Unfunded Project List, and Annual Budget Process.

Any SCR approved by TAC but assigned to the Unfunded Project List may be challenged by appeal as otherwise set forth in this Section.

21.8.8 ERCOT Impact Analysis Based on Technical Advisory Committee Recommendation Report

ERCOT shall review the TAC Recommendation Report for SCRs and update the SIA as soon as practicable, but no later than thirty (30) days after the TAC Recommendation Report is issued, unless a longer period is warranted due to the complexity of the changes proposed by TAC. If the SCR does not require a project assigned to the Unfunded Project List, ERCOT shall issue the updated SIA (if any) to the ERCOT Board and post it on the MIS within three (3) Business Days of issuance. If a longer review period is required for ERCOT to update the SIA, ERCOT shall submit a schedule for completion of the SIA to the TAC and ERCOT Board chairs.

21.8.9 ERCOT Board Vote

Upon approval of a SCR by the TAC and issuance of an SIA by ERCOT to the ERCOT Board, the ERCOT Board shall review the TAC Recommendation Report and the SIA at its next regularly scheduled meeting; provided that the SIA is available for distribution to the ERCOT Board at least eleven (11) days in advance of the ERCOT Board meeting.

The ERCOT Board shall take one of the following actions regarding the TAC Recommendation Report:

(1) approve the TAC Recommendation Report as originally submitted or as modified by the ERCOT Board; or

(2) reject the TAC Recommendation Report;

(3) defer decision on the TAC Recommendation Report; or

(4) remand the TAC Recommendation Report to TAC with instructions.

The quorum and voting requirements for ERCOT Board action are set forth in the ERCOT Bylaws.

If a motion is made to approve a TAC Recommendation Report and that motion fails, the SCR shall be deemed rejected by the ERCOT Board unless at the same meeting the ERCOT Board later votes to approve or remand the TAC Recommendation Report. The rejected SCR shall be subject to appeal pursuant to Section 21.8.12.3, Appeal of ERCOT Board Action.

21.8.10 Posting of ERCOT Board Action and Filing of Approved SCR

The ERCOT Board's action to approve or reject an SCR shall be posted on the MIS as a Board Action Report within three (3) Business Days after the ERCOT Board's action.

21.8.11 Urgent SCR Requests

The party submitting an SCR may request that the SCR be considered on an urgent basis ("Urgent") only when the submitter can reasonably show that an existing condition is impairing or could imminently impair ERCOT System reliability or wholesale or retail market operations.

If a submitter requests Urgent status for an SCR, or upon a valid motion in a regularly scheduled meeting of the Assigned TAC Subcommittee, that Subcommittee may designate the SCR for Urgent consideration if it determines that the SCR:

(1) Requires immediate attention from TAC due to:

  (a) Serious concerns about ERCOT System reliability or market operations under the unmodified language; or

(b) The crucial nature of settlement activity conducted pursuant to any settlement formula; and

(2) Is of a nature that allows for rapid implementation without negative consequence to the reliability and integrity of the ERCOT System or market operations.

The Assigned TAC Subcommittee shall consider the Urgent SCR at its earliest regularly scheduled meeting or at a special meeting called by the Assigned TAC Subcommittee chair to consider the Urgent SCR.

If the SCR is approved as Urgent, ERCOT shall submit an Urgent SCR Recommendation Report to the PRS within three (3) Business Days after the Assigned TAC Subcommittee takes action. PRS shall assign a priority and ranking for the associated project. The chair of the Assigned TAC Subcommittee may request action from PRS to accelerate or alter the procedures described herein, as needed, to address the urgency of the situation.

Upon PRS' assignment of a priority and ranking for the associated project, ERCOT shall submit an Urgent SCR Recommendation Report to the TAC within three (3) 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.

Notice of an Urgent SCR pursuant to this subsection shall be posted on the MIS. Any SCRs that take effect pursuant to an Urgent request shall be subject to an ERCOT SIA pursuant to Section 21.8.5, System Change Request Impact Analysis, and ERCOT Board consideration pursuant to Section 21.8.9, ERCOT Board Vote.

21.8.12 Appeal of Decision

The following processes are to be used to appeal a decision related to an SCR.

21.8.12.1 Appeal of Assigned TAC Subcommittee Action

Any ERCOT Member, Market Participant, PUCT Staff or ERCOT Staff may appeal directly to the TAC, any Assigned TAC Subcommittee action regarding an SCR. Such appeal to the TAC must be submitted electronically to ERCOT and the TAC Chair by completing the designated form provided on the MIS within ten (10) Business Days after the date of the relevant Assigned TAC Subcommittee appealable event. ERCOT shall reject appeals made after that time. ERCOT shall post the appeal on the ERCOT web page dedicated to the TAC and the specific SCR within three (3) Business Days of receiving the appeal. If the appeal is submitted to ERCOT at least eleven (11) days before the next regularly scheduled TAC meeting, ERCOT shall place the appeal on the agenda of the next regularly scheduled TAC meeting. If the appeal is submitted to ERCOT less than eleven (11) days before the next regularly scheduled TAC meeting, the TAC will hear the appeal at the next subsequent regularly scheduled meeting. An appeal of an SCR to TAC suspends consideration of the SCR until the appeal has been decided by TAC.

21.8.12.2 Appeal of TAC Action

Any ERCOT Member, Market Participant, PUCT Staff or ERCOT Staff may appeal directly to the ERCOT Board, any TAC action regarding an SCR. Appeals to the ERCOT Board shall be processed in accordance with the ERCOT Board Policies and Procedures. An appeal of an SCR to the ERCOT Board suspends consideration of the SCR until the appeal has been decided by the ERCOT Board.

21.8.12.3 Appeal of ERCOT Board Action

Any ERCOT Member, Market Participant or PUCT Staff may appeal any decision of the ERCOT Board regarding the SCR 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 thirty-five (35) days of the date of the relevant 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 SCR, ERCOT shall post the ruling on the MIS.

21.9 Review of Project Prioritization, Review of Unfunded Project List, and Annual Budget Process

The PRS shall recommend to TAC an assignment of a project priority for each approved PRR and SCR that involves a change in ERCOT's computer systems.

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. This review shall include review of projects on the Unfunded Project List.

TAC shall consider the project priority of each PRR and SCR and make recommendations to the ERCOT Board.

The ERCOT Board shall take one of the following actions regarding the project prioritization recommended by TAC:

(1) approve the TAC recommendation as originally submitted or as modified by the ERCOT Board; or

(2) reject the TAC recommendation; or

(3) remand the TAC recommendation to TAC with instructions.

As part of each project development, ERCOT staff shall review the Unfunded Project List and evaluate whether any unfunded projects could be included in the new project in development. If ERCOT determines that such Unfunded Project List project can be cost effectively included in the current project development, ERCOT shall post the unfunded PRR or SCR for the next scheduled PRS meeting for which proper notice can be given for PRS consideration to modify the priority and ranking assignment.

If at any time PRS modifies the priority and ranking assignment of a project associated with a PRR or SCR such that it can be funded (and thus moved out of the Unfunded Project List) in the current ERCOT budget cycle, or if ERCOT project development changes such that a project on the Unfunded Project List can be implemented, the associated PRR or SCR shall be presented to TAC for consideration of ratification of the project priority change at the next TAC meeting for which proper notice can be given. If TAC approves a priority and ranking designation of a PRR or SCR such that the associated project can be funded in the current ERCOT budget cycle, ERCOT shall revise the TAC Recommendation Report, issue the report to the ERCOT Board and post the report on the MIS within three (3) Business Days of the TAC recommendation concerning the PRR or SCR and present the PRR or SCR to the Board for consideration at the next meeting for which proper notice can given for consideration in accordance with this Section.

Each calendar quarter, ERCOT Staff and the Chair of PRS shall brief the TAC and the ERCOT Board on projects on the Unfunded Project List, which shall include distinguishing any projects originating from PUCT or ERCOT requirements and cost benefit analysis of Unfunded Project List projects.

All projects in the Unfunded Project List for more than two (2) years shall be re-evaluated by PRS as part of the annual ERCOT budget process for a possible recommendation to TAC to reject the associated PRR or SCR – which may include a recommendation to modify the PRR or SCR to eliminate the associated project; if such rejection or modification is recommended by PRS, ERCOT shall revise the associated Recommendation Report, issue the report to TAC and post the report on the MIS within three (3) Business Days of the PRS recommendation concerning the PRR or SCR for consideration at next TAC meeting for which proper notice can be given.

21.10 Review of Guide Changes

The PRS shall review changes to Market Participant guides proposed by other subcommittees that may conflict with existing Protocols and report the results of its review to the submitting subcommittee.

21.11 Process for Nodal Protocol Revisions

21.11.1 Introduction

(1) A request to make additions, edits, deletions, revisions, or clarifications to the Nodal Protocols, including any attachments and exhibits to the Nodal Protocols, is called a "Nodal Protocol Revision Request" (NPRR). Except as specifically provided for in this Section or other Sections of the Nodal Protocols, these

guidelines shall be followed for all revision requests posted during the transition period from the current zonal market design to a nodal market design. ERCOT Members, Market Participants, PUCT staff, ERCOT staff, 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 the Nodal Protocols, except for good cause shown to the PUCT or other Governmental Authority.

(2) Section 21.11 applies to NPRRs until the date of full implementation of the Texas nodal market.

(3) All decisions of the Protocol Revision Subcommittee (PRS), the Technical Advisory Committee (TAC) and the ERCOT Board (Board) with respect to any NPRR shall be posted to the MIS within three (3) Business Days of the date of the decision. All such postings shall be maintained on the MIS for at least one hundred eighty (180) days from the date of posting.

(4) The "next regularly scheduled meeting" of the PRS, TAC or the Board means 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 Board or committee procedures.

21.11.2 Submission of a Nodal Protocol Revision Request

The following Entities may submit a NPRR:

(a) Any Market Participant;

(b) Any Entity that is an ERCOT Member;

(c) PUCT staff;

(d) ERCOT staff; and

(e) Any other Entity that meets the following qualifications:

(i) Entity must reside (or represent residents) in Texas or operate in the Texas electricity market, and

(ii) Entity must demonstrate that Entity (or those it represents) is affected by the Customer Registration or Renewable Energy Credit (REC) Program Sections of the ERCOT Protocols.

21.11.3 Nodal Protocol Revision Procedure

21.11.3.1 Review and Posting of Nodal Protocol Revision Requests

(1) NPRRs shall be submitted electronically to ERCOT by completing the designated form provided on the MIS. 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;

(b) Reason for the suggested change, including whether the appropriate TAC task force has reviewed the change and the date of such consideration;

(c) 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;

(d) List of affected Nodal Protocol sections and subsections;

(e) General administrative information (organization, contact name, etc.); and

(f) Suggested language for requested revision.

(3) ERCOT shall evaluate the NPRR for completeness and shall notify the submitter, within five (5) 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 may not receive further consideration until it is completed. In order to pursue the revision requested, a submitter must submit a completed version of the NPRR with the deficiencies corrected.

(4) Once the NPRR has been determined to be complete, the NPRR must be evaluated by the ERCOT Chief Executive Officer (ERCOT CEO) or his designee before posting on the MIS. The ERCOT CEO or his designee shall make his determination within five (5) Business Days or issue a notice to the submitter advising them that additional time is necessary. Within three (3) Business Days after a determination by the ERCOT CEO or his designee, ERCOT shall notify the submitter of the NPRR of the ERCOT CEO's or his designee's decision. If the ERCOT CEO or his designee determines the NPRR is not necessary prior to the Texas Nodal Market Implementation Date, any ERCOT Member, Market Participant, Public Utility Commission of Texas (PUCT) Staff or ERCOT Staff may appeal the decision directly to the ERCOT Board. Such appeal to the ERCOT Board must be submitted to ERCOT within ten (10) Business Days after the date of the ERCOT CEO's or his designee's decision.

(5) Once a submitted NPRR has been evaluated by the ERCOT CEO or his designee, ERCOT shall post the completed NPRR and the ERCOT CEO's or his designee's decision to the MIS and distribute the NPRR to the PRS within three (3) Business Days after the ERCOT CEO's or his designee's decision has been made.

(6) Any posted NPRR that changes scope during the stakeholder process must be reevaluated by the ERCOT CEO or his designee before proceeding to the next TAC subcommittee, TAC or ERCOT Board for review.

21.11.3.2 Withdrawal of a Nodal Protocol Revision Request

(1) Upon notice to the PRS, the submitter of a NPRR may withdraw the NPRR at any time prior to consideration of the NPRR by the PRS. ERCOT shall post a notice of the submitter's withdrawal of a NPRR on the MIS within one (1) Business Day after the submitter's notice to PRS.

(2) The submitter of a NPRR may request withdrawal of a NPRR after its approval by PRS. Such withdrawal must be approved by the TAC (if it has not yet been considered by TAC) or by the Board (if it has been recommended for Board approval by TAC, but not yet considered by the Board).

(3) Once approved by the Board, a NPRR cannot be withdrawn.

21.11.3.3 Protocol Revision Subcommittee Review and Action

(1) Any interested ERCOT Member, Market Participant, PUCT staff, Texas Regional Entity (TRE) Staff or ERCOT Staff may comment on the NPRR. To receive consideration, comments must be delivered electronically to ERCOT in the designated format. Comments submitted in accordance with the instructions on the MIS shall be posted to the MIS and distributed electronically to the PRS within three (3) Business Days of submittal.

(2) The PRS shall review the NPRR at its next regularly scheduled meeting;

(3) The quorum and voting requirements for PRS action are set forth in the Technical Advisory Committee Procedures. In considering action on an NPRR, PRS may:

   (a) Recommend approval as submitted or modified;

   (c) Defer decision on the NPRR;

   (d) Refer the NPRR to a subcommittee, working group, or task force; or

   (e) Reject the NPRR.

(4) If a motion is made to recommend approval of an NPRR and that motion fails, the NPRR shall be deemed rejected by PRS unless at the same meeting PRS later votes to recommend approval of or refer the NPRR. The rejected NPRR shall be subject to appeal pursuant to Section 21.11.3.10, Appeal of Action.

(5) Within three (3) Business Days after PRS takes action, ERCOT shall issue a Report ("PRS Recommendation Report" or "PRS Action Report") reflecting the PRS action and post the same to the MIS. The PRS Report shall contain the following items:

(a) Identification of submitter;

(b) Modified Nodal Protocol language proposed by the PRS;

(c) Identification of authorship of comments;

(d) Action: recommendation for approval or approval with modified language, deferral, rejection, or referral.

(6) The PRS Recommendation Report shall be forwarded to TAC for TAC consideration. The PRS chair shall notify TAC of NPRRs rejected by PRS.

21.11.3.4 Comments to the Protocol Revision Subcommittee Recommendation Report

(1) Any interested ERCOT Member, Market Participant, PUCT Staff, TRE Staff or ERCOT Staff may comment on the PRS Recommendation Report. To receive consideration, comments on the PRS Recommendation Report must be delivered electronically to TAC and ERCOT in the designated format provided on the MIS. Comments submitted shall be posted to the MIS and distributed electronically to the TAC and PRS within three (3) Business Days of submittal.

(2) TAC shall review the PRS Recommendation Report and any posted comments to the Report at its next regularly scheduled meeting.

21.11.3.5 Nodal Protocol Revision Request Impact Analysis

(1) NPRRs that will impact nodal design systems implementation require an Impact Analysis (IA). The IA must assess the impact of the proposed NPRR on ERCOT 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, stated separately for each;

(b) The estimated amount of time required to implement the revised Nodal Protocol language and its resulting effect, if any, on the target date to start the operation of the Texas nodal market; and

(c) The identification of alternatives to the original proposed language that may result in more efficient implementation.

(2) Upon receipt of a NPRR submitted by any Entity other than ERCOT, ERCOT shall perform an initial evaluation of the impact on ERCOT and include the evaluation in ERCOT's comments. The initial evaluation will provide PRS with guidance as to whether the NPRR will impact nodal design systems implementation and what computer systems, operations, or business functions could be affected by the NPRR as submitted. ERCOT shall post its comments prior to the PRS initial review of the NPRR, if practicable.

(3) After initial review and recommendation of approval of a NPRR by the PRS, and the issuance and posting of the PRS Recommendation Report, ERCOT shall prepare an IA based on the PRS Recommendation Report to identify and evaluate the required changes to the ERCOT systems and staffing needs, including, but not limited to, ERCOT's operating systems, settlement systems, business functions, operating practices, and ERCOT System operations. If ERCOT has already prepared an IA, then ERCOT shall instead update the existing IA, if needed, to accommodate the PRS Recommendation Report.

(4) Unless a longer review period is warranted due to the complexity of the proposed PRS Recommendation Report, ERCOT shall issue the IA for the recommended NPRR within twenty-five (25) days after PRS recommendation for approval of the PRR. ERCOT shall post the results of the completed IA. If a longer review period is required for ERCOT staff to complete a full IA, ERCOT staff shall submit a schedule for completion of the IA to the PRS chair.

21.11.3.6 Protocol Revision Subcommittee Review of Impact Analysis

(1) After ERCOT posts the results of the IA, PRS shall review the IA at its next regularly scheduled meeting. PRS may revise its PRS Recommendation Report after considering the information included in the IA.

(2) If PRS revises its Recommendation Report, a revised PRS Recommendation Report shall be issued by PRS to TAC and posted on the MIS. Additional comments received regarding the revised PRS Recommendation Report shall be accepted up to three (3) Business Days prior to the TAC meeting at which the NPRR is scheduled for consideration. If PRS revises its recommendation, ERCOT shall update the IA and issue the updated IA at least three (3) Business Days prior to the regularly scheduled TAC meeting. If a longer review period is required for ERCOT to update the IA, ERCOT shall submit a schedule for completion of the IA to the TAC chair.

21.11.3.7 Technical Advisory Committee Vote

(1) TAC shall consider any NPRRs that PRS has submitted to TAC for consideration for which a PRS Recommendation Report has been posted on the MIS for at least three (3) Business Days. The following information must be included for each NPRR considered by TAC:

(a) The PRS Recommendation Report; and

(b) Any comments timely received in response to the PRS Recommendation Report.

(2) The quorum and voting requirements for TAC are set forth in the Technical Advisory Committee Procedures. In considering action on a PRS Recommendation Report, TAC shall:

(a) Recommend approval of the NPRR as recommended in the PRS Recommendation Report or as modified by TAC;

(b) Reject the NPRR;

(c) Defer decision on the NPRR;

(d) Remand the NPRR to the PRS with instructions; or

(e) Refer the NPRR to another TAC subcommittee or a TAC working group or task force with instructions.

(3) If a motion is made to recommend approval of an NPRR and that motion fails, the NPRR shall be deemed rejected by TAC unless at the same meeting TAC later votes to recommend approval of, remand or refer the NPRR. The NPRR shall be subject to appeal pursuant to Section 21.11.3.10, Appeal of Action.

(4) Within three (3) Business Days after TAC takes action, ERCOT shall issue a Report ("TAC Recommendation Report" or "TAC Action Report") reflecting the TAC action and post the same to the MIS. The TAC Report shall contain the following items:

(a) Identification of the submitter of the NPRR;

(b) Modified Nodal Protocol language proposed by TAC;

(c) Identification of the authorship of comments;

(d) PRS recommendation; and

(e) TAC recommendation or action.

(5) The TAC Recommendation Report shall be forwarded to the ERCOT Board for ERCOT Board consideration. The TAC Chair shall notify the ERCOT Board of NPRRs rejected by TAC.

21.11.3.8 ERCOT Board Vote

(1) Upon consideration of an NPRR by the TAC, the ERCOT Board shall review the TAC Recommendation Report at its next regularly scheduled meeting; provided that the Recommendation Report is available for distribution to the ERCOT Board at least eleven (11) days in advance of the ERCOT Board meeting; otherwise the NPRR will be considered by the ERCOT Board at the next regularly scheduled ERCOT Board meeting after that.

(2) The quorum and voting requirements for ERCOT Board Action are set forth in the ERCOT Bylaws. In considering action on a TAC Recommendation Report, the ERCOT Board shall:

(a) Approve the TAC Recommendation Report as originally submitted or as modified by the ERCOT Board;

(b) Reject the TAC Recommendation Report;

(c) Defer decision on the TAC Recommendation Report; or

(d) Remand the TAC Recommendation Report to TAC with instructions.

(3) If a motion is made to approve a TAC Recommendation Report and that motion fails, the NPRR shall be deemed rejected by the ERCOT Board unless at the same meeting the ERCOT Board later votes to approve or remand the TAC Recommendation Report. The rejected NPRR shall be subject to appeal pursuant to Section 21.11.3.10, Appeal of Action.

21.11.3.9 Posting of ERCOT Board Action

(1) The ERCOT Board's action regarding approval or rejection of an NPRR shall be posted on the MIS as a Board Action Report within three (3) Business Days after the ERCOT Board's action.

(2) If the ERCOT Board approves a change or changes to the Nodal Protocols, such change(s) shall be:

(a) Filed with the PUCT as soon as practicable, but no later than one (1) day before the effective date of the changes; and

(b) Incorporated into the Nodal Protocols and posted on the MIS as soon as practicable, but no later than one (1) day before the effective date of the changes.

21.11.3.10 Appeal of Action

(1) Any ERCOT Member, Market Participant, the PUCT Staff or ERCOT Staff may appeal any PRS action regarding an NPRR directly to the TAC. Such appeal to the TAC must be submitted to ERCOT within ten (10) Business Days after the date of the relevant appealable event. Appeals made after this time shall be rejected. Appeals to the TAC must be posted on the MIS within three (3) Business Days and placed on the agenda of the next available regularly scheduled TAC meeting, provided that the appeal is provided to ERCOT at least eleven (11) days in advance of the TAC meeting; otherwise the appeal will be heard by the TAC at the next regularly scheduled TAC meeting. An appeal of an NPRR to TAC suspends consideration of the NPRR until the appeal has been decided by TAC.

(2) Any ERCOT Member, Market Participant, the PUCT Staff or ERCOT Staff may appeal any TAC action regarding an NPRR directly to the ERCOT Board. Such appeal to the ERCOT Board must be submitted to ERCOT within ten (10) Business Days after the date of the relevant appealable event. An appeal of an NPRR to the ERCOT Board suspends consideration of the NPRR until the appeal has been decided by the ERCOT Board.

(3) Appeals made after this time must be rejected. Appeals to the ERCOT Board must be posted on the MIS within three (3) Business Days and placed on the agenda of the next available regularly scheduled ERCOT Board meeting, provided that the appeal is provided to the ERCOT General Counsel at least eleven (11) days in advance of the ERCOT Board meeting; otherwise the appeal will be heard by the ERCOT Board at the next regularly scheduled Board meeting.

(4) Any ERCOT Member, Market Participant or PUCT Staff may appeal any decision of the ERCOT Board regarding the NPRR to the PUCT or other Governmental Authority. Such appeal to the PUCT or other Governmental Authority must be made within thirty-five (35) days of the date of the relevant appealable event. If the PUCT or other Governmental Authority rules on the NPRR, ERCOT shall post the ruling on the MIS and shall implement the effect, if any, of the ruling on the Nodal Protocols.

21.12 Process for Transition to Nodal Market Protocol Sections

21.12.1 Introduction

ERCOT will implement the nodal market design in phases. This Section provides Market Participants with a transparent and orderly mechanism for effectuating Nodal Protocol sections and retiring Zonal Protocol sections during the transition to a nodal market design. This Section shall not be used to revise Nodal Protocols. Revisions to the Nodal Protocols shall be implemented through Section 21.11, Process for Nodal Protocol Revisions. This Section shall automatically expire at 2400 on December 31, 2009 unless terminated sooner by the ERCOT Board of Directors.

21.12.2 Notice to Market Participants of Activities Essential for Nodal Market Open

ERCOT shall issue Notices informing Market Participants of the confirmation of, or any changes to, the implementation schedules for each of the following nodal market design activities. The Notice will include an update of the implementation schedules for the remaining nodal market design activities:

(1) Single entry model;

(2) Initiation of the 168-hour testing;

(3) Completion of 168-hour test;

(4) First congestion revenue rights monthly auction;

(5) Real-time market implementation; and

(6) Day-ahead market implementation.

21.12.3 Notice to Market Participants of Effective Date for Nodal Protocol Provisions and Retirement of Zonal Protocol Provision

No part of the nodal market design may start operation until all the Market Readiness Criteria for that part of the nodal market design have been met. Certification that all Market Readiness Criteria have been met must be made at least by each of the following: the Transition Plan Task Force (TPTF), TAC, ERCOT Staff and the ERCOT Board. Upon such certification, ERCOT shall issue two Notices alerting Market Participants to the effective date of Nodal Protocol sections and the retirement of Zonal Protocol sections, as applicable. ERCOT shall issue the first Notice no less than thirty (30) days prior to the effective date or retirement date, as applicable, and the second Notice no less than ten (10) days prior to the effective date or retirement date, as applicable. The Notice shall include:

(1) The Nodal Protocol Sections to become effective and

(2) The Zonal Protocol Sections to be retired, if any.

21.12.4 Maintenance of Protocols During the Transition to a Nodal Market Design

ERCOT shall post to the MIS information contained in the Notice issued pursuant to Section 21.12.2, Notice to Market Participants of Activities Essential for Nodal Market Open, and shall post to the Texas Nodal Market Implementation website or other applicable websites projected Protocol implementation and retirement dates updated to correspond to the most recent nodal project schedule.

21.12.5 Reinstatement of Zonal Protocol Provisions

Market Participants shall maintain their zonal generation control systems for a period of thirty (30) days after the Texas nodal market implementation date. In the event of a contingency in implementation of the nodal market design for generation control subsystems (Load Frequency Control and Security Constrained Economic Dispatch as defined in the Nodal Protocols) or settlement systems that causes the ERCOT CEO to deem it necessary to reinstate a Zonal Protocol section, ERCOT shall issue a Notice stating the date and time on which the Zonal Protocol section will be reinstated. The time lines set forth in Section 21.12.2, Notice to Market Participants of Activities Essential for Nodal Market Open, shall not apply to any such reinstatement. That Notice will also include a description of the reason why the reinstatement is necessary and a proposed timeline for resolution of the system failure.

ERCOT Protocols
Section 22
Attachment A

Standard Form Black Start Agreement

February 1, 2009

Standard Form Black Start Agreement
Between
(Name of 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’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 Resource Entity as defined in the ERCOT Protocols, and Participant intends to provide Black Start 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. 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.
7620 Metro Center Drive
Austin, Texas 78744-1654
Tel No. (512) 225-7000

If to Participant:

[insert information]

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" of this Agreement begins on the Start Date and continues for a period of two (2) 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 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 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 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. Black Start Decertification.

If a Black Start Resource does not remain certified, or if it is in default as described in Section 10(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 shall refund to ERCOT any amounts paid by ERCOT under this Agreement during the Full Term.

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. <u>Planning Data.</u>

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 the next day (transmitted to the ERCOT dispatcher by 6:00 a.m. of the preceding day) pertaining to the Black Start Resource's ability to black start. The information submitted in the Availability Plan will be consistent with the information submitted in the Resource Plan; and

(2) Revised Availability Plan reflecting changes in the Plan as soon as reasonably practical, but in no event later than 60 minutes after the event that caused the change.

C. <u>Delivery.</u>

(1) ERCOT shall notify Participant, through its QSE, when the Black Start Resource must black start.

(2) If the ERCOT Transmission Grid at the Black Start Resource becomes deenergized and if Participant cannot communicate with either ERCOT or the TDSP 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 TDSP serving the Black Start Resource.

<u>Section 9. Payment.</u>

A. For the transfer of any funds under this Agreement directly between ERCOT and Participant and pursuant to the Settlement procedures for Ancillary Services described in the ERCOT Protocols, the following shall apply:

(1) Participant appoints ERCOT to act as its agent with respect to such funds transferred and authorizes ERCOT to exercise such powers and perform such duties as described in this Agreement or the ERCOT Protocols, together with such powers or duties as are reasonably incidental thereto.

(2) ERCOT shall not have any duties, responsibilities to, or fiduciary relationship with Participant and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement except as expressly set forth herein or in the ERCOT Protocols.

B. 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 test, as described in the ERCOT Protocols or Operating Guides and has not passed a subsequent black start test; or

(iv) the Black Start Resource has failed to start when required under this Agreement, and it has not passed a subsequent black start test.

(c) At its option, ERCOT may use the Black Start unit's Resource Plan as the source of Black Start availability information instead of the Availability Plan.

(2) "Hourly Rolling EAF" 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. A Force Majeure Event is treated the same as any other cause for unavailability for the purposes of calculating Hourly Rolling EAF.

(3) "Hourly Standby Fee" means, with respect to a given hour, the result determined from the following table:

Hourly Rolling EAF	Hourly Standby Fee

If Hourly Rolling EAF is more than or equal to 85%	Hourly Standby Price ($)
If Hourly Rolling EAF is less than 85% but more than 35%	Hourly Standby Price * [100%-(85%-Hourly Rolling EAF) * 2] ($)
If Hourly Rolling EAF is equal to or less than 35%	Zero

Section 10. Default.

A. Event of Default.

(1) Failure to make payment or transfer funds as provided in the ERCOT Protocols shall constitute a material breach and shall constitute an event of default ("Default") unless cured within three (3) Business Days after delivery by the non-breaching Party of written notice of the failure to the breaching Party. 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 by the breaching Party.

(2) For any material breach other than a failure to make payment or transfer funds, the occurrence and continuation of any of the following events shall constitute an event of Default by Participant:

(a) Except as excused under subsection (4) or (5) below, a material breach, other than a failure to make payment or transfer funds, of this Agreement by Participant, including any material failure by Participant to comply with the ERCOT Protocols, 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 by ERCOT of written notice of such material breach by Participant 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 rolling 12-month period, the fourth such breach shall constitute a Default.

(b) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within 90 days thereafter.

(c) The Black Start Resource's operation is abandoned without an intent to return it to operation during the Full Term; or

(d) At any time, the Hourly Rolling EAF is equal to or less than 50%.

(e) An Available Black Start Resource fails to perform successfully as required during a partial or full ERCOT system black out.

(3) Except as excused under subsection (4) or (5) below, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a failure to make payment or transfer funds, 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 rolling 12-month period, the fourth such breach shall constitute a Default.

(4) For any material breach other than a failure to make payment or transfer funds, the breach shall not result in a Default if the breach cannot reasonably be cured within 14 calendar days, prompt written notice is provided by the breaching Party to the other Party, and the breaching Party began work or other efforts to cure the breach within 3 Business Days after delivery of the notice to the breaching Party and prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(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) 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.

(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.

(c) If as a final result of any dispute resolution ERCOT, as the settlement agent, is determined to have over-collected from a Market Participant(s), with the result that refunds are owed by Participant to ERCOT, as the settlement agent, such Market Participant(s) may request ERCOT to allow such Market Participant to proceed directly against Participant, in lieu of receiving full payment from ERCOT. In the event of such request, ERCOT, in it sole discretion, may agree to assign to such Market Participant ERCOT's rights to seek refunds from Participant, and Participant shall be deemed to have consented to such assignment. This subsection (c) survives termination of this Agreement.

(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 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, notices of Default, and an opportunity for the Financing Person to cure Defaults.

(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 other Market Participants in Section 10.B and the Financing Persons in Section 13.B(3), (1) 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, (2) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, and (3) 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 (1) 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 (2) 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, except as provided in Section 9.A.

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: _____________________________

ERCOT Protocols
Section 22
Attachment B

February 1, 2008

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ERCOT Protocols
Section 22
Attachment C

February 1, 2008

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ERCOT Protocols
Section 22
Attachment D

February 1, 2008

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ERCOT Protocols
Section 22
Attachment E

February 1, 2008

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ERCOT Protocols
Section 22
Attachment F

Standard Form Reliability Must-Run Agreement

October 1, 2007

Standard Form Reliability Must-Run Agreement
Between
(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'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 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: _______________1, 20_____.

B. RMR Unit:__________________________.

Term of Reliability Must-Run Service Requested: [describe]

____

C. Description of RMR Unit [*including location, number of generators, etc.*]: ____ ______________________________________, as described in more detail on Exhibit 1. If Unit is a combined cycle Generation Resource, indicate the Unit's operational capability under ERCOT Protocols Section 6.5.9(6).

D. RMR Unit Information

(1) RMR Capacity in MW: _____

(2) Power Factor Lagging

(i) _____ P.F. (at Generator Main Leads)
(ii) _____ P.F. (at high side of Main Power Transformer)

(3) Power Factor Leading

(i) _____ P.F. (at Generator Main Leads)
(ii) _____ P.F. (at high side of Main Power Transformer)

(4) Target Availability: _____

E. Delivery Point: ____________________________

F. Revenue Meter Location (Use Resource IDs): __________________________

G. Operational and Environmental Limitations (check and describe all that apply):

(1) Operational

☐ Maximum annual hours of operation: _________________
☐ Maximum annual MWh: __________________________
☐ Maximum annual starts: ___________________________
☐ Other: ____

(2) Environmental

☐ Maximum annual NOx emissions: ____________________
☐ Maximum annual SO2 emissions: ____________________
☐ Other: ____

If applicable, upon ERCOT's request, Participant shall make reasonable efforts to secure additional credits or allowances to allow additional operation of the RMR Unit if ERCOT's planned use will exceed any of the Environmental Limitations set forth above. Participant shall provide ERCOT with advance notice of the cost of these credits prior to making the purchase. The value of any additional credits acquired at ERCOT's request shall be considered Eligible Costs.

H. Prices:

(1) Excess Energy Payment Option (Choose one option)

_____Option (A): The net payment for energy above scheduled energy is based on the Market Clearing Price of Energy (MCPE) for the appropriate Settlement Interval and zone (as described in Protocols Section 6.8.1.13), less an energy rebate, as described in Protocols Section 6.8.3.7. Currently the Gross Revenue-based energy rebate percentage is equal to 10%.

_____Option (B): The net payment for energy above scheduled energy is based on the MCPE for the appropriate Settlement Interval (as described in Protocols Section 6.8.1.13), less an energy rebate of a percentage of the Net Positive Margin for energy, as described in Protocols Section 6.8.3.7. The Net Positive Margin for energy is the product of the positive difference between the Market Clearing Price of Energy (MCPE) and the RMR Energy Price times the amount of MWh delivered above the scheduled amount. Currently, the approved Net Positive Margin-based energy rebate percentage is equal to 90% of the Net Positive Margin.

(2) Hourly Operation Prices

Estimated RMR Energy Price ($ per MWh) for each 15 minutes is the sum of (x): the product of (i) the RMR Unit heat rate, in MMBtu/MWh, times (ii) estimated fuel price, in $/MMBtu, where:

(a) RMR Unit Heat Rate: ____________

(b) Estimated Fuel Price: Unless otherwise agreed by the Parties and identified in Exhibit 1 to this Agreement, the Estimated Fuel Price is the Midpoint price expressed in $/MMBtu, published in Gas Daily, in the Daily Price Survey, under the heading "East-Houston-Katy, Houston Ship Channel" for the day of RMR deployment, plus the monthly adder. The Midpoint price for Saturdays, Sundays, holidays and other days for which there is no price published in Gas Daily, is the next published Midpoint price after the day of RMR deployment. In the event that the price is not published for more than two (2) days, the most recent previous published price will be used.

(c) Estimated fuel payments for energy delivered will be adjusted for actual fuel costs incurred as described in Protocols Section 6.8.3.3(4) in effect on the date this Agreement is signed.

(3) Estimated Startup Fuel

(a) Warm Start: ____

(b) Cold Start: _____

(4) Estimated Fuel Adder:

(5) Hourly Estimated Standby Price:

(a) $________ per hour per MW of Billing Capacity for RMR Unit based on the estimated eligible cost of operating the RMR Unit.

Estimated standby payments for energy delivered will be adjusted for actual fuel costs incurred.

(6) Unexcused Misconduct Amount: $10,000 per Unexcused Misconduct Event

I. 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.
7620 Metro Center Drive
Austin, Texas 78744-1654
Tel No. (512) 225-7000
Attn: ERCOT Legal Department

If to Participant:

[insert information]

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 “Term” of this Agreement is a period of ______ months; provided however, ERCOT, at its sole discretion, may terminate this Agreement prior to the end of the Term by giving 90 days advance written notice.

(3) Any Term that extends beyond one (1) calendar 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 Price) 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; Participant is a successor in interest or any Affiliates of Participant;

(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 as they pertain to provision of Reliability Must-Run Service 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 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. 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.

(2) For all hours in which Tested Capacity is less than RMR Capacity, then Billing Capacity may be reduced as set forth in the ERCOT Protocols in effect on the date Participant signs this Agreement.

(3) After the Effective Date, ERCOT shall purchase, as part of RMR Energy, the electrical energy generated by the RMR Unit, including ramping energy, during a Capacity Test requested by ERCOT, net of auxiliary equipment and other electrical requirements of the RMR Unit that are supplied by the RMR Unit. ERCOT shall also purchase, as part of RMR Energy, any electrical energy generated by the RMR Unit during a Capacity Test requested by Participant to attempt to show that Tested Capacity equals or exceeds RMR Capacity, net of auxiliary equipment and other electrical requirements of the RMR Unit that are supplied by the RMR Unit.

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. 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 shall only be rejected 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 the next day (transmitted to the ERCOT dispatcher by 6:00 a.m. of the preceding day). The information submitted in the Availability Plan will be consistent with the information submitted in the Resource Plan;

(2) Revised Availability Plan reflecting changes in the Plan as soon as reasonably practical, but in no event later than 60 minutes after the event that caused the change; and

(3) Status of 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.

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 its QSE, of the hours and levels of generation, if any, that the RMR Unit is to operate. This information is called the "Delivery Plan." ERCOT shall notify Participant according to the Section 4, Scheduling, of the ERCOT Protocols. ERCOT shall not notify Participant to operate at levels above those stated in the Availability Plan, and ERCOT shall not notify Participant to operate the RMR Unit in a way that would violate the limitations on operation set out in Section 1 above.

(2) Participant shall produce and deliver electrical energy from the RMR Unit to the Delivery Point at the levels specified in the Delivery Plan.

(3) ERCOT may Dispatch the RMR Unit as described in the ERCOT Protocols. ERCOT may not Dispatch the RMR Unit if compliance with the Dispatch would cause the RMR Unit to exceed the Operational and Environmental Limitations, if any, set forth in Section 1 above or at levels greater than are shown in the Availability Plan. Notwithstanding the foregoing, Participant retains the responsibility for operating the RMR Unit in accordance with limits provided by applicable law.

(4) During the hours of operation of the RMR Unit specified in the Delivery Plan, Participant may bid into the Balancing Energy Services market from the RMR Unit. Participant's operation of the RMR Unit above the level necessary to deliver the level specified in the Delivery Plan, shall not be included in the calculation of whether the RMR Unit has reached the operational and Environmental Limitations set forth in Section 1 of this Agreement. ERCOT shall retain the right to use the full operational and Environmental Limitations set forth in this Agreement.

(5) *The following section is only applicable if the RMR Unit is subject to Environmental Limitations identified in Section 1.G(2).* Participant may, upon reasonable advance written notice to ERCOT, shut down the RMR Unit for the remaining Term of this Agreement if (a) the shutdown is necessary in Participant's reasonable judgment to comply with Participant's legal obligation to stay within the Environmental Limitations, (b) ERCOT's use of the RMR Unit has caused the RMR Unit to exceed, or will immediately cause the RMR Unit to exceed, the Environmental Limitations specified herein for the entire remainder of the Term of the Agreement and (c)(*i*) Participant has been unsuccessful in its reasonable attempts procuring additional credits or allowances to allowed continued operation of the RMR Unit or (*ii*) ERCOT has not requested that Participant attempt to procure additional credits or allowances. Participant may, upon reasonable advance written notice to ERCOT, temporarily suspend operation of the RMR Unit at any time, and from time to time, if the refusal is necessary in Participant's reasonable judgment to comply with Participant's legal obligation to stay within the Environmental Limitations specified herein. For purposes of determining Actual Availability, the RMR Unit shall be considered to be available at full capacity in any hours in which the RMR Unit is unavailable because Participant has exercised its rights to shut down or suspend operation under this section.

Section 9. Payment.

A. For the transfer of any funds under this Agreement directly between ERCOT and Participant and pursuant to the Settlement procedures for Ancillary Services described in the ERCOT Protocols, the following shall apply:

(1) Participant appoints ERCOT to act as its agent with respect to such funds transferred and authorizes ERCOT to exercise such powers and perform such duties as described in this Agreement or the ERCOT Protocols, together with such powers or duties as are reasonably incidental thereto.

(2) ERCOT shall not have any duties, responsibilities to, or fiduciary relationship with Participant and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement except as expressly set forth herein or in the ERCOT Protocols.

B. Energy Payments for the RMR Unit. ERCOT shall pay Participant, through Participant's QSE, for RMR Energy in accordance with the Protocols in effect on the date that Participant signs this Agreement and for Balancing Energy at the appropriate Balancing Energy Market Clearing Price (less the amount withheld under Section 8.C(4)). "Net Energy" is the total net energy delivered to ERCOT from the RMR Unit as determined by the meter reading for the RMR Unit. Net Energy is the sum of the RMR Energy and the Balancing Energy. "RMR Energy" in a particular period is the portion of the Net Energy up to and including the amount specified in the Delivery Plan for that period, and "Balancing Energy" is any Net Energy in excess of RMR Energy in a particular period.

C. Hourly Standby Fee Payments for an RMR Unit. In accordance with the ERCOT Protocols in effect on the date that Participant signs this Agreement, ERCOT shall initially pay Participant the hourly estimated Standby Price which shall be based upon Participant's estimated Eligible Costs, subject to later true-up to payment based upon actual Eligible Costs. ERCOT shall determine and pay the final Standby Price based upon Participant's actual Eligible Costs plus an Incentive Factor in accordance with the Protocols in effect on the date that Participant signs this Agreement. The Incentive Factor, initially set at 10%, may be reduced if the RMR Unit fails to perform to the contracted capacity or Target Availability, as described in the Protocols in effect on the date that Participant signs this Agreement. The Incentive Factor shall never be less than zero.

D. Performance-Related Payment Adjustments.

(1) For a RMR Unit, a "Misconduct Event" means any hour or hours during which Participant is requested to, but does not, deliver to ERCOT electrical energy at a level of at least 98% on each hour (on a kilowatt-hour/hour basis) of the level shown in the Availability Plan.

(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 Event is measured on a daily basis.

(3) Participant is excused from the Misconduct Event payment reduction arising from any Misconduct Event that is (a) not due to intentionally incomplete, inaccurate, or dishonest reporting to ERCOT by Participant of the availability of the RMR 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, ERCOT's payments to Participant are reduced by the Unexcused Misconduct Amount.

(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 to make payment or transfer funds as provided in the ERCOT Protocols shall constitute a material breach and shall constitute an event of default ("Default") unless cured within three (3) Business Days after delivery by the non-breaching Party of written notice of the failure to the breaching Party. 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 by the breaching Party.

(2) For any material breach other than a failure to make payment or transfer funds, the occurrence and continuation of any of the following events shall constitute an event of Default by Participant:

(a) Except as excused under subsection (4) or (5) below, a material breach, other than a failure to make payment or transfer funds, of this Agreement by Participant, including any material failure by Participant to comply with the ERCOT Protocols, 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 by ERCOT of written notice of such material breach by Participant 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 rolling 12-month period, the fourth such breach shall constitute a Default.

(b) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within 90 days thereafter.

(c) The RMR Unit’s operation is abandoned without intent to return it to operation during the Term;

(d) At any time, the Actual Availability is equal to or less than 50%; or

(e) Three or more unexcused Misconduct Events occur during a contract Term.

(3) Except as excused under subsection (4) or (5) below, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a failure to make payment or transfer funds, 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 rolling 12-month period, the fourth such breach shall constitute a Default.

(4) For any material breach other than a failure to make payment or transfer funds, the breach shall not result in a Default if the breach cannot reasonably be cured within 14 calendar days, prompt written notice is provided by the breaching Party to the other Party, and the breaching Party began work or other efforts to cure the breach within 3 Business Days after delivery of the notice to the breaching Party and prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(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 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.

(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 described in Section 4.B, Participant's sole remedy shall be immediate termination of this Agreement upon written notice to ERCOT.

(c) If as a final result of any dispute resolution ERCOT, as the settlement agent, is determined to have over-collected from a Market Participant(s), with the result that refunds are owed by Participant to ERCOT, as the settlement agent such Market Participant(s) may request ERCOT to allow such Market Participant to proceed directly against Participant, in lieu of receiving full payment from ERCOT. In the event of such request, ERCOT, in its sole discretion, may agree to assign to such Market Participant ERCOT's rights to seek refunds from Participant, and Participant shall be deemed to have consented to such assignment. This subsection (c) survives termination of this Agreement.

(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) 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, notices of Default, and an opportunity for the Financing Person to cure Defaults.

(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 other Market Participants in Section 10.B and the Financing Persons in Section 13.B(3), (1) 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, (2) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (3) 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 (1) 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 (2) 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 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 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 except as provided in Section 9.A.

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: _____________________________

ERCOT Protocols
Section 22
Attachment G

February 1, 2008

Intentionally left blank.

ERCOT Protocols
Section 22
Attachment H

Standard Form TCR Account Holder Agreement

January 1, 2006

Standard Form TCR Account Holder Agreement
Between
(Name of Participant)
And
Electric Reliability Council of Texas, Inc.

This TCR Account Holder Agreement ("Agreement"), effective as of ___________ 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 TCR Account Holder as defined in the ERCOT Protocols;

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 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.
7620 Metro Center Drive
Austin, Texas 78744-1654
Tel No. (512) 225-7000

If to Participant:

[insert information]

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 next March 31, or until March 31, 2002, whichever is later. 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 at the end of the Initial Term or Renewal Term in which such modification occurred. 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: (a) 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, or (b) 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 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. 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 as they pertain to operation as a TCR Account Holder.

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. Payment.

For the transfer of any funds under this Agreement directly between ERCOT and Participant and pursuant to the Settlement procedures for Ancillary Services and the TCR Auction described in the ERCOT Protocols, the following shall apply:

A. Participant appoints ERCOT to act as its agent with respect to such funds transferred and authorizes ERCOT to exercise such powers and perform such duties as described in this Agreement or the ERCOT Protocols, together with such powers or duties as are reasonably incidental thereto.

B. ERCOT shall not have any duties, responsibilities to, or fiduciary relationship with Participant and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement except as expressly set forth herein or in the ERCOT Protocols.

Section 8. Default.

A. Event of Default.

(1) Failure to make payment or transfer funds, provide collateral or designate/maintain an association with a QSE (if required by the ERCOT Protocols) as provided in the ERCOT Protocols shall constitute a material breach and shall constitute an event of default ("Default") unless cured within two (2)

Business Days after the non-breaching Party delivers to the breaching Party written notice of the breach. 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 twelve-month period, the fourth such breach shall constitute a Default by the breaching Party.

(2) For any material breach other than a material breach described in Section 8(A)(1) the occurrence and continuation of any of the following events shall constitute an event of Default by Participant:

(a) Except as excused under subsection (4) or (5) below, a material breach, other than a material breach described in Section 8(A)(1), of this Agreement by Participant, including any material failure by Participant to comply with the ERCOT Protocols, 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 by ERCOT of written notice of such material breach by Participant 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 twelve-month period, the fourth such breach shall constitute a Default.

(b) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within ninety (90) days thereafter.

(3) Except as excused under subsection (4) or (5) below, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a failure to make payment or transfer funds, 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 twelve-month period, the fourth such breach shall constitute a Default.

(4) For any material breach other than a failure to make payment or transfer funds, the breach shall not result in a Default if the breach cannot reasonably be cured within fourteen (14) calendar days, prompt written notice is provided by the breaching Party to the other Party, and the breaching Party began work or other efforts to cure the breach within three (3) Business Days after delivery of the

notice to the breaching Party and prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(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.

(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.

(c) If as a final result of any dispute resolution, ERCOT, as the settlement agent, is determined to have over-collected from a Market Participant(s), with the result that refunds are owed by Participant to ERCOT, as the settlement agent, such Market Participant(s) may request ERCOT to allow such Market Participant to proceed directly against Participant, in lieu of receiving full payment from ERCOT. In the event of such request, ERCOT, in its sole discretion, may agree to assign to such Market Participant ERCOT's rights to seek refunds from Participant, and Participant shall be deemed to have consented to such assignment. This subsection (c) survives termination of this Agreement.

(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).

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 other Market Participants in Section 8.B. and the Financing Persons in Section 11.B., (1) 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, (2) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (3) 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 (1) 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 (2) 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 except as provided in Section 7A.

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: ______________________________

ERCOT Protocols
Section 22
Attachment I

Notification of Suspension of Operations

October 1, 2004

Notification of Suspension of Operations of a Generation Resource

This Notification is required for providing notification of any Outage of a Generation Resource of greater than one hundred eighty (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 mpappl@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:

Generation Entity : ____

DUNS No.: ____

Generation Resource(s) [plant and unit number(s)] _________________________

As of ___________ [date],[1] the Generation Resource(s) will be unavailable for Dispatch by ERCOT because Generation Entity will [check one]

[ ] decommission and retire the Generation Resource (s) permanently,[2]

[ ] 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 due to a Forced Outage. Generation Entity intends to bring the Generation Resource back to service on ___________ [date].

Unless, the Generation Resource(s) will be decommissioned and retired, the estimated time to return the suspended Generation Resource to service(s) is _________ months.

[ ] Check if applicable. The Generation Entity believes that this Generation Resource(s) is inoperable due to emissions limitations or not being repairable.

[1] Pursuant to subsection (1) of Protocol §6.5.9.1, Initiation and Approval of RMR Agreements, this date must be at least (ninety) 90 days from the date ERCOT receives this Notification.
[2] ERCOT will remove the Generation Resource(s) from its registration systems if this option is selected.

The Generation Resource(s) is further described as follows:

Location: ___________ County, Texas

Number and type of generating unit(s) ____

RMR Capacity in MW: _____

A. Power Factor Lagging

(i) _____ P.F. (at Generator Main Leads); and

(ii) _____ P.F. (at high side of Main Power Transformer)

Power Factor Leading

(i) _____ P.F. (at Generator Main Leads); and

(ii) _____ P.F. (at high side of Main Power Transformer)

Delivery Point: ____________________________

B. Revenue Meter Location (Use Resource IDs): __________________________

Operational and Environmental Limitations (check and describe all that apply):

(a) Operational:

☐ Maximum annual hours of operation: _________________

☐ Maximum annual MWh: ___________________________

☐ Maximum annual starts: ___________________________

☐ Other: ____

(b) Environmental:

☐ Maximum annual NOx emissions: ____________________

☐ Maximum annual SO2 emissions: ____________________

☐ Other: ____

Part II:

Excess Energy Payment Option (A or B) ______

Proposed RMR Energy Price: ____________($/MMBtu)

Proposed Standby Price ($/MW): ____________

I understand and agree that this Notification is not confidential and does not constitute Protected Information under the ERCOT Protocols. This Notification is not intended to constitute an offer to enter into a binding agreement, but is intended only as an offer to negotiate the terms of such an agreement, in accordance with the ERCOT Protocols.

Unless the above Generation Resource(s) is inoperable due to emissions limitations or not being repairable, I certify that Generation Entity is willing to consider entering into an RMR Agreement for the Generation Resource(s).

The undersigned certifies that I am an officer of Generation Entity, that I am authorized to execute and submit this Notification on behalf of Generation 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 Protocols
Section 22
Attachment J

Standard Form Synchronous Condenser Agreement

April 1, 2006

Standard Form Synchronous Condenser Agreement
Between
(Participant)
And
Electric Reliability Council of Texas, Inc.

This Synchronous Condenser Agreement ("Agreement"), effective as of ___________ 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 Resource Entity as defined in the ERCOT Protocols, and Participant intends to supply Synchronous Condenser 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: _______________1, 20_____.

B. Synchronous Condenser ("SC") Unit:_________________________.

Term of Service: [check one]

☐ Annual

☐ Minimum Agreement Period

C. Description of Synchronous Condenser Unit [*including location, significant operational characteristics, etc.*]:

____
____________________________________, as described in more detail on Exhibit 1.

D. Capacity in MVA: _____

E. Delivery Point: ____________________________

F. Operational Limitations (check and describe all that apply):

☐ Maximum annual hours of operation: ____________________
☐ Maximum annual starts: _______________________________
☐ Other: ____

G. Prices:

(1) Hourly Operation Prices

$ ______ Per Operational Hour in which the Synchronous Condenser Unit was instructed to operate and did operate during at least part of the hour.

(2) Hourly Standby Price: $_____

(3) Unexcused Misconduct Amount: $10,000 per Unexcused Misconduct Event

H. 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.
7620 Metro Center Drive
Austin, Texas 78744-1654
Tel No. (512) 225-7000
Attn: ERCOT Legal Department

If to Participant:

[insert information]

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 "Term" of this Agreement is a period of ______ months; provided however, ERCOT, at its sole discretion, may terminate this Agreement prior to the end of the Term by giving 90 days advance written notice.

(3) Any Term that extends beyond one (1) calendar year requires ERCOT Board approval.

B. 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.

C. Termination by Mutual Agreement. This Agreement may be terminated upon written agreement of both parties at a time specified by such agreement; provided that provided that Participant may still recover Eligible Costs (Standby Price) and Incentive Factor payments already accrued prior to termination pursuant to this section.

D. 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; Participant is a successor in interest or any Affiliates of Participant;

(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 as they pertain to provision of Synchronous Condenser Service 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 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. Intentionally Omitted

Section 8. Operation.

A. Synchronous Condenser 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 Synchronous Condenser Unit for the contract Term. Participant will promptly advise ERCOT of any later changes to the schedule. The specific times for Planned Outages of the Synchronous Condenser Unit must be approved or rejected by ERCOT within thirty (30) days after submission by a Participant. Requested outages shall only be rejected 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 the next day (transmitted to the ERCOT dispatcher by 6:00 a.m. of the preceding day). The information submitted in the Availability Plan will be consistent with the information submitted in the Resource Plan;

(2) Revised Availability Plan reflecting changes in the Plan as soon as reasonably practical, but in no event later than 60 minutes after the event that caused the change; and

(3) Status of Synchronous Condenser Unit with respect to Environmental Limitations, if any.

ERCOT shall timely report to Participant the status of the Synchronous Condenser Unit with respect to Operational Limitations.

C. <u>Delivery.</u>

(1) ERCOT shall notify Participant, through its QSE, of the hours and levels of generation, if any, that the Synchronous Condenser Unit is to operate. This information is called the "Delivery Plan." ERCOT shall notify Participant according to the Section 4, Scheduling, of the ERCOT Protocols. ERCOT shall not notify Participant to operate at levels above those stated in the Availability Plan, and ERCOT shall not notify Participant to operate the Synchronous Condenser Unit in a way that would violate the limitations on operation set out in Section 1 above.

(2) Participant shall produce and deliver VARs from the Synchronous Condenser Unit to the Delivery Point at the levels specified in the Delivery Plan.

(3) ERCOT may Dispatch the Synchronous Condenser Unit only as described in the ERCOT Protocols. ERCOT may not Dispatch the Synchronous Condenser Unit if compliance with the Dispatch would cause the Synchronous Condenser Unit to exceed the Operational Limitations, if any, set forth in Section 1 above or at levels greater than are shown in the Availability Plan. Notwithstanding the foregoing, Participant retains the responsibility for operating the Synchronous Condenser Unit in accordance with limits provided by applicable law.

<u>Section 9. Payment.</u>

A. For the transfer of any funds under this Agreement directly between ERCOT and Participant and pursuant to the Settlement procedures for Ancillary Services described in the ERCOT Protocols, the following shall apply:

(1) Participant appoints ERCOT to act as its agent with respect to such funds transferred and authorizes ERCOT to exercise such powers and perform such duties as described in this Agreement or the ERCOT Protocols, together with such powers or duties as are reasonably incidental thereto.

(2) ERCOT shall not have any duties, responsibilities to, or fiduciary relationship with Participant and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement except as expressly set forth herein or in the ERCOT Protocols.

B. <u>Hourly Operation Payments for the Synchronous Condenser Unit.</u> ERCOT shall pay Participant, through Participant's QSE, for all hours or partial hours that the Synchronous Condenser was connected to the ERCOT Transmission Grid due to an instruction from ERCOT. The payment for each hour or partial hour will be the Synchronous Condenser Unit Hourly Operation Price.

C. Hourly Standby Price Payments for a Synchronous Condenser Unit.

(1) "Available" means, with respect to a given hour, that Participant has declared, in its Availability Plan, that the Synchronous Condenser Unit is able to synchronize to the ERCOT Transmission Grid, provided that the Synchronous Condenser Unit is not "Available" if it has failed a synchronous Condenser Test or has failed to synchronize to the ERCOT Transmission Grid when required to do so under this Agreement, and it has not since passed a subsequent Synchronous Condenser Test.

(2) "Hourly Rolling EAF" 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 Synchronous Condenser Unit 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 Synchronous Condenser Unit shall be deemed, for purposes of this calculation, to be Available for that Assumed Hour. A Force Majeure Event is treated the same as any other cause for unavailability for the purposes of calculating Hourly Rolling EAF.

(3) "Hourly Standby Fee" means, with respect to a given hour, the result determined from the following table:

Hourly Rolling EAF	Hourly Standby Fee
If Hourly Rolling EAF is more than or equal to 85%	Hourly Standby Price ($)
If Hourly Rolling EAF is less than 85% but more than 35%	Hourly Standby Price * [100%-(85%-Hourly Rolling EAF) * 2] ($)
If Hourly Rolling EAF is equal to or less than 35%	Zero

D. ERCOT shall pay Participant for each successful Instructed Start at the Start Price. "Instructed Start" is the start of the operation of the Synchronous Condenser Unit at ERCOT's request.

E. Performance-Related Payment Adjustments.

(1) For a Synchronous Condenser Unit, a "Misconduct Event" means any hour or hours during which Participant is requested to, but does not, synchronize the Unit to the ERCOT Transmission Grid during any hour in which the Unit is shown Available in the Availability Plan.

(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 Event is measured on a daily basis.

(3) Participant is excused from the Misconduct Event payment reduction arising from any Misconduct Event that is (a) not due to intentionally incomplete, inaccurate, or dishonest reporting to ERCOT by Participant of the availability of the Synchronous Condenser 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, ERCOT's payments to Participant are reduced by the Unexcused Misconduct Amount.

(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 9.G against any amounts due by ERCOT to Participant under this Agreement.

Section 10. Default.

A. Event of Default.

(1) Failure to make payment or transfer funds as provided in the ERCOT Protocols shall constitute a material breach and shall constitute an event of default ("Default") unless cured within three (3) Business Days after delivery by the non-breaching Party of written notice of the failure to the breaching Party. 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 by the breaching Party.

(2) For any material breach other than a failure to make payment or transfer funds, the occurrence and continuation of any of the following events shall constitute an event of Default by Participant:

(a) Except as excused under subsection (4) or (5) below, a material breach, other than a failure to make payment or transfer funds, of this Agreement by Participant, including any material failure by Participant to comply with the ERCOT Protocols, 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 by ERCOT of written notice of such material breach by Participant 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 rolling 12-month period, the fourth such breach shall constitute a Default.

(b) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within 90 days thereafter.

(c) The Synchronous Condenser Unit's operation is abandoned without intent to return it to operation during the Term;

(d) At any time, the Hourly Rolling EAF is equal to or less than 50%; or

(e) Three or more unexcused Misconduct Events occur during a contract Term.

(3) Except as excused under subsection (4) or (5) below, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a failure to make payment or transfer funds, 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 rolling 12-month period, the fourth such breach shall constitute a Default.

(4) For any material breach other than a failure to make payment or transfer funds, the breach shall not result in a Default if the breach cannot reasonably be cured within 14 calendar days, prompt written notice is provided by the breaching Party to the other Party, and the breaching Party began work or other efforts to cure the breach within 3 Business Days after delivery of the notice to the breaching Party and prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(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.

(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.

(c) If as a final result of any dispute resolution ERCOT, as the settlement agent, is determined to have over-collected from a Market Participant(s), with the result that refunds are owed by Participant to ERCOT, as the settlement agent such Market Participant(s) may request ERCOT to allow such Market Participant to proceed directly against Participant, in lieu of receiving full payment from ERCOT. In the event of such request, ERCOT, in its sole discretion, may agree to assign to such Market Participant ERCOT's rights to seek refunds from Participant, and Participant shall be deemed to have consented to such assignment. This subsection (c) survives termination of this Agreement.

(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, notices of Default, and an opportunity for the Financing Person to cure Defaults.

(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 other Market Participants in Section 10.B and the Financing Persons in Section 13.B(3), (1) 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, (2) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (3) 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 (1) 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 (2) 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 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 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 except as provided in Section 9.A.

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: _____________________________

ERCOT Protocols
Section 22
Attachment K
Standard Form

Emergency Interruptible Load Service (EILS) Agreement

December 11, 2007

Standard Form Emergency Interruptible Load Service (EILS)
Supplement to QSE Agreement
Between
(Name of Participant)
and
Electric Reliability Council of Texas, Inc.

This Supplement to QSE 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 Interruptible Load Service" ("EILS Rule") providing for the creation of a special emergency service known as Emergency Interruptible Load Service ("EILS"); and

B. Participant is a QSE in the ERCOT Region and has executed a Standard Form Qualified Scheduling Entity Agreement ("QSE Agreement") with ERCOT; and

C. Participant is the QSE representing an entity or entities owning or controlling EILS Resource(s) that will be obligated to provide EILS; and

D. Participant and ERCOT wish to supplement the QSE Agreement between Participant and ERCOT to provide for Participant to represent EILS Resources wishing to participate in the EILS; 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 EILS.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the "Parties") hereby agree as follows:

A. All terms and conditions of the QSE Agreement between Participant and ERCOT remain in full force and effect.

[1] Unless otherwise indicated, capitalized terms in this Agreement have the meanings ascribed to them in the ERCOT Protocols.

B. In addition to its obligations under the QSE Agreement with ERCOT, Participant will submit bids for EILS on behalf of the entities set forth in Appendix A 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 EILS Rule as well as all ERCOT Protocols and Technical Requirements concerning EILS.

D. Participant and ERCOT agree that each award of EILS will be confirmed by a terms and conditions sheet ("Term Sheet") provided by ERCOT to Participant in a form substantially the same as the form attached hereto as Appendix B.

E. Either Party may terminate this Supplement by providing thirty days notice to the other Party; *provided, however*, no termination of this Supplement will be effective before the end of an EILS Contract Period for which ERCOT has already issued a Term Sheet 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: ____

Appendix A

To Supplement to QSE Agreement

The Entity that owns or controls the following EILS Resource hereby acknowledges that it understands and will comply with PUCT SUBST. Rule 25.507 and the ERCOT Protocols relating to EILS.

Acknowledgement by EILS Resource Owning or Controlling Entity	
Company Name	
Authorized Representative Name	
Title	
Address Line1	
Address Line 2	
City/State/ZIP	
Phone	
Email Address	

[ENTITY NAME]

By:____
[Signature]

Printed Name:__________________________________

Its:____
[Title]

Date:____

Appendix B

Supplement to QSE Agreement

This Term Sheet is subject to the QSE Agreement and EILS Supplement thereto between _________________ and Electric Reliability Council of Texas, Inc. dated ________________________________. The terms of this Term Sheet are binding on both parties.

EMERGENCY INTERRUPTIBLE LOAD DEMAND RESPONSE TERM SHEET							
Load Type	[Individual] [Aggregated]						
Contract Period	Months						
Emergency Interruptible Load Resource	**EILS Load 1**	**EILS Load 2**	**EILS Load 3**	**EILS Load 4**	**EILS Load 5**	**EILS Load 6**	**EILS Load 7**
Resource Owner/Operator							
Resource Common Name							
Meter Reading Entity (TDSP)							
Meter Reading Entity Duns Number							
QSE Name							
QSE Duns Number							
Load within a NOIE Service Area (Y or N)*							
Load within a Private Use Network (Y or N)**							
ESI ID*** or unique service identifier assigned to meter (MUST BE IDR)							

Baseline Methodology (Default or Alternate)							
RFP EILS Time Period (xxxx-yyyy) Award Amounts							
Awarded Interruptible Capacity (MW)							
Price ($/MW) to be applied to each hour of the contract period							
Minimum Base Load (MW) associated with this ESI ID or unique service identifier that will not be interrupted as part of the EILS deployment							

Complete a version of this page for each RFP Time Period that the EILS Resource Offer is awarded or accepted.

* If the EIL Resource is within a NOIE network, the submitter will be required to submit meter data specific to that load as required in Section 6.5.12, Emergency Interruptible Load Service (EILS), item (17).
** If the EIL Resource is on a Private Use Network, the submitter will be required to submit meter data specific to that load as required in Section 6.5.12, Emergency Interruptible Load Service (EILS), item (17).

*** If the EIL Resource is within a NOIE network, use unique service identifier.

ERCOT Protocols
Section 22
Attachment L

Standard Form Market Participant Agreement

August 1, 2007

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

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
7620 Metro Center Drive
Austin, Texas 78744-1654
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. <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. Payment.

For the transfer of any funds under this Agreement directly between ERCOT and Participant and pursuant to the Settlement procedures for Ancillary Services described in the ERCOT Protocols, the following shall apply:

A. Participant appoints ERCOT to act as its agent with respect to such funds transferred and authorizes ERCOT to exercise such powers and perform such duties as described in this Agreement or the ERCOT Protocols, together with such powers or duties as are reasonably incidental thereto.

B. ERCOT shall not have any duties, responsibilities to, or fiduciary relationship with Participant and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement except as expressly set forth herein or in the ERCOT Protocols.

Section 8. Default.

A. Event of Default.

(1) Failure to make payment or transfer funds, provide collateral or designate/maintain an association with a QSE (if required by the ERCOT Protocols) as provided in the ERCOT Protocols shall constitute a material breach and shall constitute an event of default ("Default") unless cured within two (2) Business Days after the non-breaching Party delivers to the breaching Party written notice of the breach. 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 twelve-month period, the fourth such breach shall constitute a Default by the breaching Party.

(2) For any material breach other than a material breach described in Section 8(A)(1) the occurrence and continuation of any of the following events shall constitute an event of Default by Participant:

(a) Except as excused under subsection (4) or (5) below, a material breach, other than a material breach described in Section 8(A)(1), of this Agreement by Participant, including any material failure by Participant to comply with the ERCOT Protocols, 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 by ERCOT of written notice of such material breach by Participant 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 twelve-month period, the fourth such breach shall constitute a Default.

(b) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within 90 days thereafter.

(3) Except as excused under subsection (4) or (5) below, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a failure to make payment or transfer funds, 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 twelve-month period, the fourth such breach shall constitute a Default.

(4) For any material breach other than a failure to make payment or transfer funds, the breach shall not result in a Default if the breach cannot reasonably be cured within fourteen (14) calendar days, prompt written notice is provided by the breaching Party to the other Party, and the breaching Party began work or other efforts to cure the breach within three (3) Business Days after delivery of the notice to the breaching Party and prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(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.

(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.

(c) If as a final result of any dispute resolution, ERCOT, as the settlement agent, is determined to have over-collected from a Market Participant(s), with the result that refunds are owed by Participant to ERCOT, as the settlement agent, such Market Participant(s) may request ERCOT to allow such Market Participant to proceed directly against Participant, in lieu of receiving full payment from ERCOT. In the event of such request, ERCOT, in its sole discretion, may agree to assign to such Market Participant ERCOT's rights to seek refunds from Participant, and Participant shall be deemed to have consented to such assignment. This subsection (c) survives termination of this Agreement.

(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. <u>No Third Party Beneficiary.</u> Except with respect to the rights of other Market Participants in Section 8.B. and the Financing Persons in Section 11.B., (i) 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, (ii) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (iii) 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: (i) 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 (ii) 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 except as provided in Section 7A.

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:

[USE OPTION 1 IF PARTICIPANT IS A CORPORATION

By: ____

Name: ____

Title: ____

Date:________________________________

USE OPTION 2 IF PARTICIPANT IS A LIMITED PARTNERSHIP

By: ____,
as General Partner for [Participant]

Name:____

Title:____

Date:____

Market Participant Name:
____

Market Participant DUNS: ______________________________]

ERCOT Protocols
Section 22
Attachment M

Notification of Change of Generation Resource Designation

October 1, 2007

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 mpappl@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.

Generation Entity: ____

DUNS No.: ____

Generation Resource(s) [plant and unit number(s)] _______________________________

Generation Resource is currently [check one]

[ ] under an RMR Agreement

[ ] mothballed

As of ___________ [date], Generation Entity will change the Generation Resource designation to [check one]

[ ] operational

[ ] mothballed

[ ] decommissioned and retired permanently[1]

[1] ERCOT will remove the Generation Resource(s) from its registration systems if this option is selected.

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 Protocols
Section 22
Attachment N

Amendment to Standard Form Market Participant Agreement

April 1, 2008

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

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:

[USE OPTION 1 IF PARTICIPANT IS A CORPORATION

By: ____

Name: ____

Title: ____

Date:______________________________

USE OPTION 2 IF PARTICIPANT IS A LIMITED PARTNERSHIP

By: ____,
as General Partner for [Participant]

Name:____

Title:____

Date:____

Market Participant Name:
____

Market Participant DUNS: ____________________________]

ERCOT Protocols
Section 23: Texas Test Plan Team – Retail Market Testing

September 1, 2005

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23 TEXAS TEST PLAN TEAM – RETAIL MARKET TESTING

This Section contains an overview of the purpose and scope of the Texas Test Plan Team (TTPT). It also refers to the standards that are defined in the Texas Market Test Plan (TMTP). This Section applies to ERCOT, CRs and TDSPs serving areas where Customer Choice is in effect. This information is posted on the ERCOT website.

23.1 Overview

The Texas Test Plan Team (TTPT) is an ERCOT standing working group that reports to the Retail Market Subcommittee (RMS). The TTPT is comprised of volunteers from Market Participant (MP) companies. These volunteers work in a cooperative manner to establish processes and procedures for testing the commercial operations to verify retail systems are in compliance with ERCOT Protocols and PUCT rulemakings.

The TTPT processes and procedures for testing represent the consensus view of MPs directly involved in the testing process.

The TTPT evaluates market processes defined by the ERCOT Protocols, other Retail Market Subcommittee working groups, and PUCT rulemakings to establish testing requirements and materials necessary to validate those processes among MPs.

ERCOT may enlist the services of an Independent Third Party Testing Administrator (ITPTA) in this testing process.

The TTPT works with the ERCOT Flight Administrator to ensure that testing processes and procedures are defined for the Market and that the content of those materials are thoroughly and equitably administered with all participants.

23.2 Testing Participants

The following parties conduct market compliance testing and abide by the testing process defined by the TTPT:

(1) ERCOT;

(2) TDSP; and

(3) CR.

23.3 Documentation and Testing Materials

The TTPT develops and maintains a test plan and related testing standards. The processes and procedures for testing are defined in the TMTP and on the retail testing website, which is administered by ERCOT.

23.4 Market Changes

The TTPT stays abreast of changes within the ERCOT market (e.g. TX SET guidelines, Texas Data Transport Working Group (TDTWG) communication Protocols, ERCOT Protocols, and PUCT rulemakings) and develops testing processes to validate changes. When such changes occur, the TTPT modifies the testing standards defined in the TMTP as needed to provide for adequate testing of all affected market systems. Testing of these changes is scheduled to allow ERCOT and all MPs adequate time to modify their systems and participate in the testing process.

23.5 Testing Success

Testing success is defined according to the information in the TMTP and the test scripts. The ERCOT Flight Administrator is the final authority on all levels of business process certification among trading partners, including the verification that a party has successfully passed testing and is eligible to go into production.

ERCOT Protocols
Section 24: Retail Point to Point Communications

June 25, 2007

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24 RETAIL POINT TO POINT COMMUNICATIONS

Point to point communications include transactions flowing directly between Competitive Retailers (CRs) and Transmission and/or 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 CR sends maintenance related information to the TDSP using the 650_01, Service Order Request. The 650_01 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 (1) Retail Business Day after completion, or attempted completion, of the requested action using the 650_02 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 service order request/response transactions.

24.1.1 Disconnect/Reconnect

PUCT rules and regulations, along with TDSPs Tariff, 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

The 650_04, Suspension of Delivery Service Notification transaction is electronically transmitted by the TDSP to 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:

(1) 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.

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(2) 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.

(3) 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. In events where the CR receives a 650_04 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 (10) Retail Business Days.

(4) 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 notification indicating that the suspension has been cancelled and send a 650_04 notification to the CR for every ESI ID that would have been affected by the outage.

To notify the CR of a suspension of delivery service, the TDSP sends notice to the CR using the 650_04. To reject the suspension of delivery service notification, a CR would send a response to the TDSP using the 650_05, Suspension of Delivery Service Reject Response within one (1) Retail Business Day of receipt of the 650_04.

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 for each ESI ID that would otherwise have been affected by the outage. To reject the suspension of delivery service cancellation, a CR must send a response to the TDSP using the 650_05 within one (1) Retail Business Day of receipt of the 650_04.

24.2 Transmission Distribution Service Provider to Competitive Retailer Invoice

The 810_02, TDSP to CR 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 ANSI X12 validation, the CR shall have five (5) Business Days to send a rejection response in accordance with the TX SET Implementation Guides and Public Utility Commission of Texas (PUCT) 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.

Only one 810_02 may be sent for a single service period, however, any additional 810_02 for the same ESI ID may be sent for a Late Payment charge after the thirty fifth (35th) calendar day for an unpaid 810_02 or for interest credit.

The 810_02 may be paired with an 867_03, Monthly Usage to trigger the Customer billing process.

The TDSP may cancel and replace (rebill) the original 810_02. 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.

If the 867_03 is cancelled after the TDSP has sent the 810_02, the TDSP will cancel the 810_02. If the 810_02 error is not related to consumption the TDSP may cancel the 810_02 and not the 867_03.

24.3 Monthly Remittance

TDSPs and CRs shall use the following transactions to remit monthly payments.

24.3.1 CR to TDSP Monthly Remittance Advice

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.

Each Market Participant (MP) is responsible for ensuring that the data provided in the 820_02 is presented in a format that is consistent with market specifications prescribed in the Texas Standard Electronic Transaction (TX SET) 820_02 Implementation Guide.

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 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 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 (5) 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.

24.4 MOU/EC TDSP to CR Monthly Remittance Advice

This transaction set, from a Municipally Owned Utility's TDSP or an Electric Cooperative's TDSP (MOU/EC TDSP) to the 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, Remittance Advice for every CR account number even when a cancel and restatement of usage subsequently cancels the original Invoice.

Each MP is responsible for ensuring that the data provided in the 820_03 is presented in a format that is consistent with the market specifications in the 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 (5) Retail Business Days of the due date of the retail Customer's bill, or if the Customer has paid after the due date, five (5) 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 (5) 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 remittance 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 CR to a 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 CR and to continually provide TDSP updates of such information.

24.5.1 Timing of 814_PC Maintain Customer Information Request from CR

This transaction shall be transmitted from the CR of Record to the TDSP in one (1) Retail Business Day only after the CR has received an 867_04, Initial Meter Read Notification 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 Usage for that specific move-out Customer. The TDSP shall provide the 814_PD, Maintain Customer Information Response transaction in one (1) Retail Business Day acknowledging receipt of the 814_PC, Maintain Customer Information Request transaction, 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 MOU/EC TDSP to the 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 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 MOU/EC TDSP

This transaction shall be transmitted from the MOU/EC TDSP to the CR in one (1) Retail Business Day upon an update in Customer information. The CR shall provide the 814_PD transaction in one (1) Retail Business Day acknowledging receipt of the 814_PC transaction, which would indicate that the CR accepts or rejects the transaction.

ERCOT Fee Schedule

Effective March 1, 2009

The following is a schedule of ERCOT fees currently in effect.

Description	Protocol Reference	Calculation/Rate/Comment
ERCOT System Administration fee	9.7.1	$0.4171 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 fees	9.7.5	Actual cost of using third party communications network - initial equipment installation cost not to exceed $18,000, and monthly network management fee not to exceed $865.
ERCOT Nodal Implementation Surcharge	9.7.6	$0.169/MWh – Charged to all QSEs representing net metered generation.
ERCOT Security Screening Study (Not Refundable)	NA	A preliminary study of the impacts of a proposed generation plant conducted by ERCOT staff - $1,000 (10MW to 74MW) $2,000 (75MW to 149 MW) $3,000 (150MW to 249MW) $4,000 (250MW to 499MW) $5,000 (500MW and above)
Full Interconnection Study	NA	Costs incurred by the Transmission and/or Distribution Service Provider (TDSP) for completing a detailed study - $15 per MW (Not Refundable – to support ERCOT system studies and coordination)
Map Sale fees	NA	$20 - $40 per map request (by size)
Qualified Scheduling Entity Application fee	9.7.4	$500 per Entity
Competitive Retailer Application fee	9.7.4	$500 per Entity
Mismatched Schedule Processing fee	9.7.3	$1 per mismatched event - Assessed to QSEs submitting schedules referencing each other where the schedules do not match
Voluminous Copy fee	NA	$0.15 per page in excess of 50 pages
Late fees	9.4.6	Wall Street Journal prime interest rate plus two (2) percent – assessed for failure to make timely payment under the Protocols.