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| NPRR Number | [995](http://www.ercot.com/mktrules/issues/NPRR995) | NPRR Title | RTF-6 Create Definition and Terms for Settlement Only Energy Storage |
| Date of Decision | | January 14, 2021 | |
| Action | | Tabled | |
| Timeline | | Normal | |
| Proposed Effective Date | | To be determined | |
| Priority and Rank Assigned | | To be determined | |
| Nodal Protocol Sections Requiring Revision | | 1.2, Functions of ERCOT  1.3.1.1, Items Considered Protected Information  1.6.5, Interconnection of New or Existing Generation  2.1, Definitions  2.2, Acronyms and Abbreviations  3.1.6.9, Withdrawal of Approval or Acceptance and Rescheduling of Approved or Accepted Planned Outages of Resource Facilities  3.7, Resource Parameters  3.8.7, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)  3.10.1, Time Line for Network Operations Model Changes  3.10.6, Resource Entity Responsibilities  3.10.7.2, Modeling of Resources and Transmission Loads  3.14.4.1, Overview and Description of MRAs  6.3.2, Activities for Real-Time Operations  6.5.5.2, Operational Data Requirements  6.5.9.4.2, EEA Levels  6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone  6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG)  6.6.10, Real-Time Revenue Neutrality Allocation  8.1.1.4.2, Responsive Reserve Energy Deployment Criteria  8.5.1.1, Governor in Service  8.5.1.2, Reporting  8.5.2, Primary Frequency Response Measurements  8.5.2.1, ERCOT Required Primary Frequency Response  9.5.3, Real-Time Market Settlement Charge Types  9.17.1, Billing Determinant Data Elements  9.19.1, Default Uplift Invoices  10.1, Overview  10.2.2, TSP and DSP Metered Entities  10.2.3, ERCOT-Polled Settlement Meters  10.2.3.1, Entity EPS Responsibilities  10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values  10.2.4.1, Responsibilities for Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values  10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters  10.9.1, ERCOT-Polled Settlement Meters  11.1.6, ERCOT Polled Settlement Meter Netting  16.5, Registration of a Resource Entity  16.5.1.2, Waiver for Federal Hydroelectric Facilities  16.11.4.3.2, Real-Time Liability Estimate  22 Attachment L, Declaration of Private Use Network Net Generation Capacity Availability  23 Form I, Resource Entity Application for Registration | |
| Related Documents Requiring Revision/Related Revision Requests | | None | |
| Revision Description | | This Nodal Protocol Revision Request (NPRR) accomplishes objectives of the Resource Definition Task Force (RTF) undertaken at the direction of the Protocol Revision Subcommittee (PRS).  Specifically, this NPRR:   * Provides a definition for the term Settlement Only Energy Storage System (SOESS) and further defines them as transmission-connected or distribution-connected; * Relocates the definition for Settlement Only Generator (SOG) from underneath Resource to stand alone as its own unrelated term; and * Incorporates the relevant SOESS terms into the Market Information System (MIS) reporting created for SOGs via NPRR917, Nodal Pricing for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs). | |
| Reason for Revision | | Addresses current operational issues.  Meets Strategic goals (tied to the [ERCOT Strategic Plan](http://www.ercot.com/content/news/presentations/2013/ERCOT%20Strat%20Plan%20FINAL%20112213.pdf) or directed by the ERCOT Board).  Market efficiencies or enhancements  Administrative  Regulatory requirements  Other: (explain)  *(please select all that apply)* | |
| Business Case | | This NPRR provides clarity as to how SOESS will be treated within the ERCOT market. | |
| Credit Work Group Review | | ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR995 and do not believe that it requires changes to credit monitoring activity or the calculation of liability. | |
| PRS Decision | | On 2/13/20, PRS unanimously voted to table NPRR995. All Market Segments were present for the vote.  On 11/11/20, PRS unanimously voted via roll call to recommend approval of NPRR995 as amended by the 10/28/20 ERCOT comments. All Market Segments were present for the vote.  On 12/10/20, PRS unanimously voted via roll call to table NPRR995. All Market Segments were present for the vote.  On 1/14/21, PRS voted via roll call to table NPRR995. There was one abstention from the Independent Power Marketer (IPM) (Morgan Stanley) Market Segment. All Market Segments were present for the vote. | |
| Summary of PRS Discussion | | On 2/13/20, the sponsor reviewed the intent of NPRR995, and participants expressed a desire to table NPRR995 to allow for further review of energy storage issues within other stakeholder forums, including the Battery Energy Storage Task Force (BESTF), RTF, and upcoming Distribution Generation Resource (DGR) workshop(s).  On 11/11/20, there was no discussion.  On 12/10/20, participants noted the 12/7/20 ERCOT comments requesting an additional month to develop the Impact Analysis for NPRR995.  On 1/14/21, participants reviewed the Impact Analysis for NPRR995; discussed the 1/12/21 ERCOT comments noting potential impacts to the Passport schedule from NPRR995; and requested a workshop to discuss NPRR995 and related NPRRs which are not currently within the scope of Passport, but cover issues which may need to be addressed prior to Passport implementation. | |

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| Sponsor | |
| Name | Bob Wittmeyer |
| E-mail Address | [Bwittmeyer@longhornpower.com](mailto:Bwittmeyer@longhornpower.com) |
| Company | Longhorn Power on behalf of Broad Reach Power |
| Phone Number | 512-762-8895 |
| Cell Number |  |
| Market Segment | Not applicable |

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| **Market Rules Staff Contact** | |
| **Name** | Cory Phillips |
| **E-Mail Address** | [cory.phillips@ercot.com](mailto:cory.phillips@ercot.com) |
| **Phone Number** | 512-248-6464 |

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| **Comments Received** | |
| Comment Author | **Comment Summary** |
| ERCOT 020620 | Requested PRS table NPRR995 for additional review by the BESTF |
| ERCOT 040920 | Removed the definitions for Distribution Energy Storage Resource (DESR) and Transmission Energy Storage Resource (TESR) and clarified the definitions of Settlement Only Transmission Energy Storage (SOTES) and Settlement Only Transmission Self-Energy Storage (SOTSES) |
| WMS 060820 | Requested PRS continue to table NPRR995 |
| ERCOT 091020 | Proposed additional revisions to several additional Protocol sections to ensure proper pricing for charging and discharging these Resources |
| ERCOT 101920 | Proposed additional revisions to establish additional requirements and clarifications relating to SOESS |
| ERCOT 102820 | Proposed minor corrections to the 10/19/20 ERCOT comments |
| WMS 110620 | Endorsed NPRR995 as amended by the 10/28/20 ERCOT comments |
| ERCOT 120720 | Proposed an alternative schedule for the development of an Impact Analysis for NPRR995, stating ERCOT intends to complete the Impact Analysis prior to the January 14, 2021 PRS meeting |
| ERCOT 121620 | Proposed corrections to billing determinants and descriptions in paragraph (2) of Section 6.6.10 |
| ERCOT 011221 | Requested PRS table NPRR995 for additional analysis of NPRRs which may be approved pre-Passport for implementation post-Passport. |

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| **Market Rules Notes** |

Please note that the baseline definition of “Resource” has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

* NPRR990, Relocation of Combined Cycle Train to Resource Attribute (incorporated 9/1/20)
* NPRR1016, Clarify Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) (incorporated 9/1/20)
* NPRR1029, BESTF-6 DC-Coupled Resources (incorporated 1/1/21)

Please note that the baseline definition of “Resource Attribute” has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

* NPRR967, Remove the 10 MW Limit from the Definition of Limited Duration Resource (LDR) (incorporated 3/1/20)
* NPRR973, Add Definitions for Generator Step-Up and Main Power Transformer (incorporated 9/1/20)
* NPRR986, BESTF-2 Energy Storage Resource Energy Offer Curves, Pricing, Dispatch, and Mitigation (incorporated 3/1/20)
* NPRR990, Relocation of Combined Cycle Train to Resource Attribute (incorporated 9/1/20)
* NPRR1000, Elimination of Dynamically Scheduled Resources (incorporated 9/1/20)
* NPRR1013, RTC – NP 1, 2, 16, and 25: Overview, Definitions and Acronyms, Registration and Qualification of Market Participants, and Market Suspension and Restart (incorporated 1/1/21)
* NPRR1016, Clarify Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) (incorporated 9/1/20)

Please note that the baseline definition of “Resource Entity” has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

* NPRR989, BESTF-1 Energy Storage Resource Technical Requirements (incorporated 7/1/20)

Please note that the baseline definition of “Resource Registration” has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

* NPRR1003, Elimination of References to Resource Asset Registration Form (incorporated 9/1/20)

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

* NPRR945, Net Metering Requirements (incorporated 1/1/21)
  + Section 10.3.2.3
* NPRR1000, Elimination of Dynamically Scheduled Resources (incorporated 9/1/20)
  + Section 6.3.2
* NPRR1006, Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data (incorporated 7/1/20)
  + Section 6.3.2
* NPRR1007, RTC – NP 3: Management Activities for the ERCOT System (incorporated 1/1/21)
  + Section 3.14.4.1
* NPRR1010, RTC – NP 6: Adjustment Period and Real-Time Operations (incorporated 1/1/21)
  + Section 6.3.2
  + Section 6.5.5.2
  + Section 6.5.9.4.2
  + Section 6.6.3.9
* NPRR1011, RTC – NP 8: Performance Monitoring (incorporated 1/1/21)
  + Section 8.1.1.4.2
  + Section 8.5.1.1
* NPRR1012, RTC – NP 9: Settlement and Billing (incorporated 1/1/21)
  + Section 9.5.3
  + Section 9.19.1
* NPRR1013, RTC – NP 1, 2, 16, and 25: Overview, Definitions and Acronyms, Registration and Qualification of Market Participants, and Market Suspension and Restart (incorporated 1/1/21)
  + Section 1.3.1.1
  + Section 16.11.4.3.2
* NPRR1014, BESTF-4 Energy Storage Resource Single Model (incorporated 1/1/21)
  + Section 6.5.5.2
* NPRR1029, BESTF-6 DC-Coupled Resources (incorporated 1/1/21)
  + Section 6.5.5.2
* NPRR1035, DC Tie Schedules Protected Information Expiry and Posting (incorporated 10/14/20)
  + Section 1.3.1.1
* NPRR1039, Replace the Term MIS Public Area with ERCOT Website (incorporated 1/1/21)
  + Section 1.2
  + Section 3.1.6.9
  + Section 3.10.1
  + Section 6.3.2
  + Section 6.5.9.4.2
  + Section 8.5.2
  + Section 9.17.1
  + Section 10.2.2
* NPRR1041, Adjust Expiration of Protected Information Status for Wholesale Storage Load (WSL) Data (incorporated 1/1/21)
  + Section 1.3.1.1
* NPRR1043, Clarification of NPRR986 Language Related to Wholesale Storage Load (incorporated 1/1/21)
  + Section 6.6.3.2
  + Section 10.2.3
  + Section 11.1.6
* NPRR1047, Consolidate Greybox re NPRR973 and NPRR1016 (incorporated 1/1/21)
  + Section 3.10.7.2

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

* NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)
  + Section 3.10.7.2
  + Section 10.3.2.3
* NPRR1052, Load Zone Pricing for Settlement Only Storage Prior to NPRR995 Implementation
  + Section 6.6.3.2
  + Section 6.6.3.9
  + Section 9.19.1
  + Section 16.5
* NPRR1054, Removal of Oklaunion Exemption Language
  + Section 6.6.10
  + Section 9.5.3
  + Section 16.11.4.3.2

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| Proposed Protocol Language Revision |

**1.2 Functions of ERCOT**

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

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

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

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

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

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

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

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

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

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

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

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| ***[NPRR857: Replace paragraph (7) above with the following upon system implementation:]***  (7) Nothing in these Protocols may be construed as causing TSPs, DSPs, Direct Current Tie Operators (DCTOs), or Resources to transfer any control of their Facilities to ERCOT. |

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

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

**1.3.1.1 Items Considered Protected Information**

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

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

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

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

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

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

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| ***[NPRR1013: Replace paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (b) Bids, offers, or pricing information identifiable to a specific Qualified Scheduling Entity (QSE) or Resource. The Protected Information status of part of this information shall expire 60 days after the applicable Operating Day, as follows:  (i) Ancillary Service Offers by Operating Hour or Security-Constrained Economic Dispatch (SCED) interval for each Resource for all Ancillary Services submitted for the Day-Ahead Market (DAM) or Real-Time Market (RTM);  (ii) The quantity of Ancillary Service offered by Operating Hour or SCED interval for each Resource for all Ancillary Service submitted for the DAM or RTM; and  (iii) A Resource’s Energy Offer Curve prices and quantities by Operating Hour or SCED interval. The Protected Information status of this information shall expire within seven days after the applicable Operating Day if required to be posted as part of paragraph (5) of Section 3.2.5 and within two days after the applicable Operating Day if required to be posted as part of paragraph (7) of Section 3.2.5; |

(c) Status of Resources, including Outages, limitations, or scheduled or metered Resource data. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

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

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

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

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| ***[NPRR1013: Replace paragraph (f) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (f) Ancillary Service awards identifiable to a specific QSE or Resource. The Protected Information status of this information shall expire 60 days after the applicable Operating Day; |

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

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

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

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

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

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

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

(l) Information related to generation interconnection requests, to the extent such information is not otherwise publicly available. The Protected Information status of certain generation interconnection request information expires as provided in Section 1.3.3, Expiration of Confidentiality;

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| ***[NPRR902: Replace paragraph (l) above with the following upon system implementation, but no earlier than July 1, 2020:]***  (l) Information related to generation interconnection requests, to the extent such information is not otherwise publicly available. The Protected Information status of certain generation interconnection request information expires as provided in Section 1.3.1.4, Expiration of Protected Information Status; |

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

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

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

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

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

(p) Credit limits identifiable to a specific QSE;

(q) Any information that is designated as Protected Information in writing by Disclosing Party at the time the information is provided to Receiving Party except for information that is expressly designated not to be Protected Information by Section 1.3.1.2 or that, pursuant to Section 1.3.3, is no longer confidential;

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| ***[NPRR902: Replace paragraph (q) above with the following upon system implementation, but no earlier than July 1, 2020:]***  (q) Any information that is designated as Protected Information in writing by Disclosing Party at the time the information is provided to Receiving Party except for information that is expressly designated not to be Protected Information by Section 1.3.1.2 or that, pursuant to Section 1.3.1.4, is no longer confidential; |

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

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

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

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| ***[NPRR857: Replace item (t) above with the following upon system implementation:]***  (t) QSE, Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), and Distribution Service Provider (DSP) backup plans collected by ERCOT under the Protocols or Other Binding Documents; |

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

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

(i) PUCT Substantive Rules on performance measure reporting;

(ii) These Protocols or Other Binding Documents; or

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

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

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

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

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

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

(bb) Generation Resource emergency operations plans and weatherization plans;

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

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

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

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| ***[NPRR829: Replace paragraph (ee) above with the following upon system implementation:]***  (ee) Status of Settlement Only Generators (SOGs) and Settlement Only Energy Storage System (SOESS), including Outages, limitations, schedules, metered output and withdrawal data, or data telemetered for use in the calculation of Real-Time Liability (RTL) as described in Section 16.11.4.3.2, Real-Time Liability Estimate, except that ERCOT may disclose metered output and withdrawal data from an SOG or SOESS as part of an extract or forwarded TX SET transaction provided to the LSE associated with the ESI ID of the Premise where the SOG is located. The Protected Information status of this information shall expire 60 days after the applicable Operating Day; |

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

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

(hh) Information provided to ERCOT under Section 16.18, Cybersecurity Incident Notification, except that ERCOT may disclose general information concerning a Cybersecurity Incident in a Market Notice in accordance with paragraph (5) of Section 16.18 to assist Market Participants in mitigating risk associated with a Cybersecurity Incident; and

(ii) Information disclosed in response to paragraphs (1)-(4) of the Gas Pipeline Coordination section of Section 22, Attachment K, Declaration of Completion of Generation Resource Summer Weatherization Preparations and Natural Gas Pipeline Coordination for Resource Entities with Natural Gas Generation Resources, submitted to ERCOT in accordance with Section 3.21.1, Natural Gas Pipeline Coordination Requirements for Resource Entities with Natural Gas Generation Resources for Summer Preparedness and Summer Peak Load Season. The Protected Information status of Resource Outage information shall expire as provided in paragraph (1)(c) of Section 1.3.1.1.

***1.6.5 Interconnection of New or Existing Generation***

(1) Interconnection of new Generation Resources, Settlement Only Generators (SOGs), or Settlement Only Energy Storage Systems (SOESSs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents. For existing Generation Resources, SOGs, and SOESSs which connect to a new Point of Interconnection (POI) or which utilize more than one POI to the ERCOT Transmission Grid, any Protocol or Other Binding Document requirements applicable to Generation Resources, SOGs, and SOESSs which are based upon the execution date of the Standard Generation Interconnection Agreement (SGIA) shall be applied to the date of the first executed SGIA with the following exceptions:

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

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

## 2.1 DEFINITIONS

**Generation Entity**

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

**Initial Energization**

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

**Initial Synchronization**

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

**Interconnecting Entity (IE)**

Any Entity that has submitted a Generation Interconnection or Change Request Application for a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) and meets the requirements of Planning Guide Section 5.1.1, Applicability.

**Must-Run Alternative (MRA)**

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

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| ***[NPRR885: Replace the above definition “Must-Run Alternative (MRA)” with the following upon system implementation:]***  **Must-Run Alternative (MRA)**  A resource operated under the terms of an Agreement with ERCOT as an alternative to a Reliability Must-Run (RMR) Unit. An MRA may be one of the following:  ***Generation Resource MRA***  A generator that is registered with ERCOT as a Generation Resource that is dispatchable in Security-Constrained Economic Dispatch (SCED) and is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT.  ***Other Generation MRA***  Unregistered generation, or generation registered with ERCOT that is not dispatchable in Security-Constrained Economic Dispatch (SCED), that is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT. An Other Generation MRA may include, but is not limited to, Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs) and Distributed Generation (DG).  ***Demand Response MRA***  A Load providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT by reducing energy consumption in response to an ERCOT instruction. A Demand Response MRA may be an unregistered Load or a registered Load Resource other than a Controllable Load Resource.  ***Weather-Sensitive MRA***  A type of Must-Run Alternative (MRA) Service in which a Demand Response MRA provides MRA Service only after meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1, Emergency Response Service Procurement. |

**Non-WSL Settlement Only Charging Load**

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

**Primary Frequency Response**

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

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| ***[NPRR989: Replace the above definition “Primary Frequency Response” with the following upon system implementation:]***  **Primary Frequency Response**  The immediate proportional increase or decrease in real power output provided by Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), Generation Resources, Energy Storage Resources (ESRs), Controllable Load Resources, and the natural real power dampening response provided by Load in response to system frequency deviations. This response is in the direction that stabilizes frequency. |

**Resource**

The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term “Resource” used by itself in these Protocols does not include a Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or an Emergency Response Service (ERS) Resource.

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

An Energy Storage System (ESS) registered with ERCOT for the purpose of providing energy and/or Ancillary Service to the ERCOT System.

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| [NPRR1029: Insert the following definition “DC-Coupled Resource upon system implementation:]  ***DC-Coupled Resource***  A type of Energy Storage Resource (ESR) in which an Energy Storage System (ESS) is combined with wind and/or solar generation in the same modeled generation station and interconnected at the same Point of Interconnection (POI), and where these technologies are interconnected within the site using direct current (DC) equipment. The combined technologies are then connected to the ERCOT System using the same direct current-to-alternating current (DC-to-AC) inverter(s). To be classified as a DC-Coupled Resource, the generator(s) and ESS(s) at a site must meet the following conditions:  (1) The ESS component of the Resource must have a nameplate rating of at least ten MW and ten MWh, or the MW rating must equal or exceed 50% of the nameplate MW rating of the inverter; and  (2) All intermittent renewable generators must meet the conditions for aggregation stated in paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, except to the extent any such condition requires the generator to be a Resource. |

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| ***[NPRR1016: Insert the following definition “Distribution Energy Storage Resource (DESR)” upon system implementation:]***  ***Distribution Energy Storage Resource (DESR)***  An Energy Storage Resource (ESR) connected to the Distribution System that is either:  (1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or  (2) Greater than one MW that chooses to register as a Resource with ERCOT to participate in the ERCOT markets. |

***Generation Resource***

A generator capable of providing energy or Ancillary Service to the ERCOT System and is registered with ERCOT as a Generation Resource.

***Distribution Generation Resource (DGR)***

A Generation Resource connected to the Distribution System that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Ten MW or less that chooses to register as a Generation Resource to participate in the ERCOT markets.

DGRs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

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| ***[NPRR1016: Replace the definition “Distribution Generation Resource (DGR)” above with the following upon system implementation:]***  ***Distribution Generation Resource (DGR)***  A Generation Resource connected to the Distribution System that is either:  (1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or  (2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets. |

***Transmission Generation Resource (TGR)***

A Generation Resource connected to the ERCOT transmission system that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Ten MW or less that chooses to register as a Generation Resource to participate in the ERCOT markets.

TGRs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

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| ***[NPRR1016: Replace the definition “Transmission Generation Resource (TGR)” above with the following upon system implementation:]***  ***Transmission Generation Resource (TGR)***  A Generation Resource connected to the ERCOT transmission system that is either:  (1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or  (2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets. |

***Load Resource***

A Load capable of providing Ancillary Service to the ERCOT System and/or energy in the form of Demand response and registered with ERCOT as a Load Resource.

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

A Load Resource that is an aggregation of individual metered sites, each of which has less than ten MW of Demand response capability and all of which are located within a single Load Zone.

***Controllable Load Resource***

A Load Resource capable of controllably reducing or increasing consumption under Dispatch control by ERCOT.

**Resource Attribute**

Specific qualities associated with various Resources (i.e., specific aspects of a Resource or the services the Resource is qualified to provide).

***Aggregate Generation Resource (AGR)***

A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are interconnected at the same Point of Interconnection (POI) and located behind the same Generator Step-Up (GSU) transformer (with a high-side voltage greater than 60 kV).

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| ***[NPRR973: Replace the definition “Aggregate Generation Resource (AGR)” above with the following upon system implementation of PR106:]***  ***Aggregate Generation Resource (AGR)***  A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are interconnected at the same Point of Interconnection (POI) and located behind the same Main Power Transformer (MPT). |

***Black Start Resource***

A Generation Resource under contract with ERCOT to provide Black Start Service (BSS).

***Combined Cycle Train***

The combinations of gas turbines and steam turbines in an electric generation plant that employs more than one thermodynamic cycle. For example, a Combined Cycle Train refers to the combination of gas turbine generators (operating on the Brayton Cycle) with turbine exhaust waste heat boilers and steam turbine generators (operating on the Rankine Cycle) for the production of electric power. In the ERCOT market, Combined Cycle Trains are each registered as a plant that can operate as a Generation Resource in one or more Combined Cycle Generation Resource configurations.

***Decommissioned Generation Resource***

A Generation Resource for which a Resource Entity has submitted a Notification of Suspension of Operations or a Notification of Change of Generation Resource Designation, for which ERCOT has declined to execute a Reliability Must-Run (RMR) Agreement, and which has been decommissioned and permanently retired.

***Dynamically Scheduled Resource (DSR)***

A Resource that has been designated by the Qualified Scheduling Entity (QSE), and approved by ERCOT, as a DSR status-type and that follows a DSR Load.

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| ***[NPRR1000: Delete the definition “Dynamically Scheduled Resource (DSR)” above upon system implementation.]*** |

***Intermittent Renewable Resource (IRR)***

A Generation Resource that can only produce energy from variable, uncontrollable Resources, such as wind, solar, or run-of-the-river hydroelectricity.

***Intermittent Renewable Resource (IRR) Group***

A group of two or more IRRs whose performance in responding to Security-Constrained Economic Dispatch (SCED) Dispatch Instructions will be assessed as an aggregate for Generation Resource Energy Deployment Performance (GREDP) and Base Point Deviation. An IRR Group cannot contain any IRRs that are Split Generation Resources. Additionally, only IRRs that have the same Resource Node can be mapped to an IRR Group. Resource Entities can choose to group IRRs and shall provide the grouping information in a timely manner for ERCOT review prior to the scheduled database loads.

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| [NPRR1013: Replace the definition “Intermittent Renewable Resource (IRR) Group” above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]  ***Intermittent Renewable Resource (IRR) Group***  A group of two or more IRRs whose performance in responding to Security-Constrained Economic Dispatch (SCED) Dispatch Instructions will be assessed as an aggregate for Generation Resource Energy Deployment Performance (GREDP) and Set Point Deviation. An IRR Group cannot contain any IRRs that are Split Generation Resources. Additionally, only IRRs that have the same Resource Node can be mapped to an IRR Group. Resource Entities can choose to group IRRs and shall provide the grouping information in a timely manner for ERCOT review prior to the scheduled database loads. |

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| ***[NPRR1016: Insert the following definition “Inverter-Based Resource (IBR)” upon system implementation:]***  ***Inverter-Based Resource (IBR)***  A Resource that is connected to the ERCOT System either completely or partially through a power electronic converter interface. |

***Limited* *Duration* *Resource* (*LDR*)**

An Energy Storage Resource (ESR) that may be unavailable to Security-Constrained Economic Dispatch (SCED) due to the need to maintain its current state of charge.

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| ***[NPRR986: Delete the definition “Limited Duration Resource (LDR)” above upon system implementation.]*** |

***Mothballed Generation Resource***

A Generation Resource for which a Resource Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute a Reliability Must-Run (RMR) Agreement, and which has not been decommissioned and retired.

***Quick Start Generation Resource (QSGR)***

A Generation Resource that in its cold-temperature state can come On-Line within ten minutes of receiving ERCOT notice and has passed an ERCOT QSGR test that establishes an amount of capacity that can be deployed within a ten-minute period.

***Split Generation Resource***

Where a Generation Resource has been split to function as two or more independent Generation Resources in accordance with Section 10.3.2.1, Generation Resource Meter Splitting, and Section 3.10.7.2, Modeling of Resources and Transmission Loads, each such functionality independent Generation Resource is a Split Generation Resource.

***Switchable Generation Resource (SWGR)***

A Generation Resource that can be connected to either the ERCOT Transmission Grid or a non-ERCOT Control Area.

Resource Entity

An Entity that owns or controls a Generation Resource, a Settlement Only Generator (SOG), a Settlement Only Energy Storage System (SOESS), or a Load Resource and is registered with ERCOT as a Resource Entity.

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| ***[NPRR989: Replace the above definition “Resource Entity” with the following upon system implementation:]***  **Resource Entity**  An Entity that owns or controls a Generation Resource, an Energy Storage Resource (ESR), a Settlement Only Generator (SOG), a Settlement Only Energy Storage System (SOESS), or a Load Resource and is registered with ERCOT as a Resource Entity. |

Resource Registration

Provision of information required by ERCOT to register Generation Resources, Settlement Only Generators (SOGs), Load Resources, Settlement Only Energy Storage Systems (SOESSs), and Energy Storage Resources (ESRs).

***Settlement Only Energy Storage System (SOESS)***

An Energy Storage System (ESS) that is settled for imported/exported energy only, but may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or submit energy offers or bids. These units are comprised of:

***Settlement Only Distribution Energy Storage System (SODESS)***

An Energy Storage System (ESS) connected to the Distribution System with a rating of:

(1) One MW or less that chooses to register as an SODESS; or

(2) Greater than one and up to ten MW that is capable of providing a net export to the ERCOT System and does not register as a Distribution Energy Storage Resource (DESR).

***Settlement Only Transmission Energy Storage System (SOTESS)***

An Energy Storage System (ESS) connected to the ERCOT transmission system with a rating of ten MW or less that has not been registered as an Energy Storage Resource (ESR).

***Settlement Only Generator (SOG)***

A generator that is settled for exported energy only, but may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or submit energy offers. These units are comprised of:

***Settlement Only Distribution Generator (SODG)***

A generator that is connected to the Distribution System with a rating of:

(1) One MW or less that chooses to register as an SODG; or

(2) Greater than one and up to ten MW that is capable of providing a net export to the ERCOT System and does not register as a Distribution Generation Resource (DGR).

SODGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

***Settlement Only Transmission Generator (SOTG)***

A generator that is connected to the ERCOT transmission system with a rating of ten MW or less and is registered with the Public Utility Commission of Texas (PUCT) as a power generation company.

SOTGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and may be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

***Settlement Only Transmission Self-Generator (SOTSG)***

A generator that is connected to the ERCOT transmission system with a rating of one MW or more and is registered with the Public Utility Commission of Texas (PUCT) as a self-generator.

SOTSGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.3, Modeling of Private Use Networks.

## 2.2 ACRONYMS AND ABBREVIATIONS

**SODESS** Settlement Only Distribution Energy Storage System

**SOESS** Settlement Only Energy Storage System

**SOTESS** Settlement Only Transmission Energy Storage System

**3.1.6.9 Withdrawal of Approval or Acceptance and Rescheduling of Approved or Accepted Planned Outages of Resource Facilities**

(1) If ERCOT believes it cannot meet applicable reliability standards and has exercised all other reasonable options, and the delayed initiation of, or early termination of, one or more approved or accepted Resource Outages not addressed by Section 3.1.4.6, Outage Coordination of Potential Transmission Emergency Conditions, could resolve the situation, then ERCOT shall issue an Advance Action Notice (AAN) pursuant to Section 6.5.9.3.1.1, Advance Action Notice.

(a) The AAN shall describe the reliability problem, the date and time that the possible Emergency Condition would begin, the date and time that the possible Emergency Condition would end, and a summary of the actions ERCOT believes it might take, including, if applicable, the amount of capacity it would seek from an Outage Adjustment Evaluation (OAE) and OSAs. The AAN must state the time at which ERCOT will execute an OAE, if an OAE is deemed necessary.

(b) ERCOT shall issue the AAN a minimum of 24 hours prior to performing an OAE. Additionally, unless impracticable pursuant to paragraph (3)(f) below, the OAE should not be performed until eight Business Hours have elapsed following issuance of the AAN. ERCOT shall not issue an OSA under this Section unless it has first completed an OAE.

(c) Following the AAN, ERCOT may communicate with Market Participants about the reliability problem, however, ERCOT may not provide information about market conditions to a subset of Market Participants that is not generally available to all Market Participants.

(d) As conditions change, ERCOT shall, to the extent practicable, update the AAN in order to provide simultaneous notice to Market Participants.

(e) This section does not limit Transmission and/or Distribution Service Provider (TDSP) access to ERCOT data and communications.

(2) QSEs shall update their Resource COPs and the Outage Scheduler to the best of their ability before the time stated in the AAN when ERCOT will execute the OAE, to reflect any decisions to voluntarily delay or cancel any Outage prior to the OAE so as to remove the Outage from OAE and OSA consideration.

(3) If, after the planned OAE execution time has passed as noted in paragraph (1)(b) above, ERCOT continues to forecast an inability to meet applicable reliability standards after the updates to the Resource COPs and Outage Schedules, ERCOT may conduct an OAE and issue one or more OSAs.

(a) ERCOT may contact QSEs representing Resources to be included in the OAE for more information prior to conducting an OAE or issuing an OSA.

(b) ERCOT may not consider nuclear-powered Generation Resources for an OSA.

(c) Prior to the execution of an OAE, a QSE may notify ERCOT that a specific Resource cannot be considered in the OAE, for all or part of the period covered by the AAN, due to Resource reliability, compliance with contractual warranty obligations, or other reasons beyond the QSE’s control. ERCOT will not consider this Resource in the OAE.

(d) In order to determine which Outages to delay, ERCOT shall first consider the Outage duration, dividing the Outages in categories of zero to two days, two to four days, four to seven days, or more than seven days, then withdraw approval or acceptance on a last in, first out basis within that duration category, so that shorter Outages are delayed first, and the timing of Outage submissions is considered within that category.

(e) ERCOT may only issue an OSA to the QSE for a Resource that has a COP Resource Status of OUT within the forecasted Emergency Condition described above in this section.

(f) If the Resource Outage for which the OSA would be issued is scheduled to begin before eight Business Hours have elapsed following issuance of the AAN, ERCOT may issue the OSA prior to the beginning of the Resource Outage after the end of the 24-hour notice period.

(g) Following the receipt of an OSA, during the OSA Period:

(i) The QSE for the Resource may choose to show the Resource as OFF in the COP or may elect to leave the Resource On-Line due to equipment or reliability concerns or if the Resource Category is coal or lignite. If the Resource remains On-Line, it must utilize a status of ONRUC.

(ii) If the Resource remains On-Line pursuant to paragraph (i) above, it must remain at Low Sustained Limit (LSL) unless deployed above LSL by Security-Constrained Economic Dispatch (SCED). In addition, the QSE must update the Resource’s Energy Offer Curve to $4,500 for all MWs above LSL.

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| ***[NPRR930: Replace paragraph (ii) above with the following upon system implementation:]***  (ii) If the Resource remains On-Line pursuant to paragraph (i) above, it must remain at Low Sustained Limit (LSL) unless deployed above LSL by Security-Constrained Economic Dispatch (SCED). |

(iii) If the Resource chooses to show the Resource as OFF in the COP, the Resource may not be self-committed during the OSA Period and shall only be available for commitment by Reliability Unit Commitment.

(4) ERCOT shall work in good faith with the QSEs to reschedule any delayed or canceled Outages resulting from an AAN under paragraph (1) above, regardless of whether the Resource took voluntary actions or received an OSA. The Outage must be rescheduled so that it is completed within 120 days of the end of the OSA Period.

(a) If ERCOT issues an OSA, the QSE may submit a new request for approval of the Planned Outage schedule, however the new Outage may not begin prior to the end time of the OSA Period.

(b) If a transmission Outage was scheduled in coordination with a Resource Outage that is delayed, ERCOT shall also delay that transmission Outage when necessary.

(5) If insufficient capacity to meet the need described in the AAN is made available through the processes described in paragraphs (2) and (3) above, ERCOT may contact QSEs having Resources with a Resource Status of OUT in the most recently submitted COP to determine if it is feasible for the Outage of those Resources to be ended by the time of the possible Emergency Condition described in the AAN. ERCOT may issue an OSA to the QSE for any Resource that the QSE agrees can feasibly be returned to service during the period of the possible Emergency Condition described in the AAN.

(6) If system conditions change such that the need described in the AAN increases, ERCOT shall update the AAN and may repeat the process described in this section. For any subsequent iterations of this process, ERCOT shall issue the updated AAN with as much lead time as is practical prior to starting any subsequent OAE, but with a minimum of two hours’ notice.

(7) ERCOT must perform a planning assessment to determine whether to issue an AAN or OSA. The planning assessment may not assume total renewable production lower than the sum of the selected Wind-powered Generation Resource Production Potential (WGRPP) and PhotoVoltaic Generation Resource Production Potential (PVGRPP) forecasts for each hour less any reasonably expected severe weather impacts. The available capacity in ERCOT’s planning assessment must include targeted reserve levels and include forecasted capacity available through DC Tie imports or curtailment of DC Tie exports, forecasted capacity provided from Settlement Only Distributed Generators (SODGs), Settlement Only Transmission Generators (SOTGs), Settlement Only Distribution Energy Storage Systems (SODESSs), and Settlement Only Transmission Energy Storage Systems (SOTESSs), and forecasted capacity from price-responsive Demand based on information reported to ERCOT in accordance with Section 3.10.7.2.1, Reporting of Demand Response. ERCOT must post the following inputs of the planning assessment to the ERCOT website within an hour of issuing an AAN, including but not limited to:

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

(k) SODG, SOTG, SODESS, and SOTESS forecasts;

(l) The forecast of capacity provided by price-responsive Demand;

(m) Any aggregate derating of Resource(s) and/or Forced Outage assumptions in total MWs; and

(n) Any aggregated fuel derating assumptions in total MWs.

(8) Notwithstanding anything in this Section, ERCOT need not comply with any other requirement in this Section if the occurrence of an unforeseen Real-Time condition requires that ERCOT withdraw approval of one or more Resource Outages in order to meet applicable reliability standards. The unforeseen Real-Time condition cannot be the result of changes that Ancillary Services are procured to address. In exercising its discretion under this paragraph, ERCOT is not required to issue an AAN or OAE before issuing an OSA, but shall:

(a) Issue the OSA to the QSE of the Resource for the purpose of make whole compensation; and

(b) Present the justification for the out of market action to the Technical Advisory Committee (TAC) at its next meeting that is at least 14 Business Days after the OSA.

**3.7 Resource Parameters**

(1) A Resource Entity shall register Generation Resources, Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Load Resources pursuant to Planning Guide Section 6.8, Resource Registration Procedures. The Resource Parameters, listed in Section 3.7.1, Resource Parameter Criteria, are a subset of Resource Registration data defined in the Resource Registration Glossary.

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| ***[NPRR1002: Replace paragraph (1) above with the following upon system implementation:]***  (1) A Resource Entity shall register its Generation Resources, Energy Storage Resources (ESRs), Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Load Resources pursuant to Planning Guide Section 6.8, Resource Registration Procedures. The Resource Parameters, listed in Section 3.7.1, Resource Parameter Criteria, are a subset of Resource Registration data defined in the Resource Registration Glossary. |

(2) ERCOT shall provide each Qualified Scheduling Entity (QSE) that represents a Resource the ability to submit changes to Resource Parameters for that Resource as described in Section 3.7.1.

(3) The QSE may revise Resource Parameters only with sufficient documentation to justify a change in Resource Parameters.

(4) ERCOT shall use the Resource Parameters as inputs into the Day-Ahead Market (DAM), Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), Resource Limit Calculator, Load Frequency Control (LFC), and other ERCOT business processes.

(5) The Independent Market Monitor (IMM) may require the QSE to provide justification for the Resource Parameters submitted.

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| ***[NPRR1016: Insert Section 3.8.7 below upon system implementation:]***  ***3.8.7 Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)***  (1) As a condition for the interconnection of a DGR or DESR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall provide documentation from the DSP to ERCOT stating that the interconnecting distribution circuit will not be disconnected as part of an Energy Emergency Alert (EEA) Level 3, an under-frequency Load shedding event, or an under-voltage Load shedding event, unless required for DSP local system maintenance or during a DSP local system emergency.  (a) If a DSP subsequently determines that any circuit to which a DGR or DESR is interconnected will need to be disconnected during these Load shedding events, or that a DGR or DESR will need to be moved to a circuit that will be disconnected during these Load shedding events:  (i) The DSP shall promptly notify the designated contact for the DGR or DESR;  (ii) The Resource Entity shall promptly notify ERCOT of this fact via the Resource Registration process; and  (iii) The DGR or DESR will immediately be disqualified from offering to provide any Ancillary Service.  (b) Upon receiving notification from the DSP that the DGR or DESR is no longer subject to disconnection during any of these Load shedding events, and that no known system limitations or changes have occurred that would inhibit the DGR or DESR from complying with Ancillary Service performance requirements, the Resource Entity for the DGR or DESR shall notify ERCOT of this fact via the Resource Registration process and will, at that time, be eligible to offer to provide Ancillary Services if the Resource is otherwise qualified to do so.  (2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or for a proposed conversion of an existing Settlement Only Distribution Energy Storage System (SODESS) to a DESR, the interconnecting DSP will evaluate the proposed conversion and will determine whether it is electrically and operationally feasible. If the interconnecting DSP determines that the conversion is not electrically or operationally feasible, the DSP may disallow the conversion.  (3) The Resource Node for a DGR or DESR shall be fixed at a single Electrical Bus in the ERCOT Network Operations Model.  (a) If a DSP determines that a topology change has altered, or is expected to alter, the electrical path connecting the DGR or DESR to the ERCOT Transmission Grid for a period longer than 60 days:  (i) The DSP shall promptly notify the interconnecting Transmission Service Provider (TSP) and the designated contact for the DGR or DESR, and the interconnecting TSP shall notify ERCOT; and  (ii) The Resource Entity shall submit a change request to ERCOT via the Resource Registration process. |

***3.10.1 Time Line for Network Operations Model Changes***

(1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

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| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation:]***  (1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs, DCTOs, and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates. |

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource, Settlement Only Generator (SOG), or Settlement Only Energy Storage System (SOESS) as described in Planning Guide Section 5, Generation Resource Interconnection or Change Request, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource, SOG, or SOESS.

(3) TSPs and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. ERCOT shall update the Network Operations Model according to the following table:

| **Deadline to Submit Information to ERCOT**  **Note 1** | **Model Complete and Available for Test**  **Note 2** | **Updated Network Operations Model Testing Complete**  **Note 3**  **Paragraph (5)** | **Update Network Operations Model Production Environment** | **Target Physical Equipment included in Production Model**  **Note 4** |
| --- | --- | --- | --- | --- |
| Jan 1 | Feb 15 | March 15 | April 1 | Month of April |
| Feb 1 | March 15 | April 15 | May 1 | Month of May |
| March 1 | April 15 | May 15 | June 1 | Month of June |
| April 1 | May 15 | June 15 | July 1 | Month of July |
| May 1 | June 15 | July 15 | August 1 | Month of August |
| June 1 | July 15 | August 15 | September 1 | Month of September |
| July 1 | August 15 | September 15 | October 1 | Month of October |
| August 1 | September 15 | October 15 | November 1 | Month of November |
| September 1 | October 15 | November 15 | December 1 | Month of December |
| October 1 | November 15 | December 15 | January 1 | Month of January (the next year) |
| November 1 | December 15 | January 15 | February 1 | Month of February (the next year) |
| December 1 | January 15 | February 15 | March 1 | Month of March (the next year) |

Notes:

1. TSP and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.

2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.

3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.

4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

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| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation:]***  (3) TSPs, DCTOs, and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. ERCOT shall update the Network Operations Model according to the following table:   | **Deadline to Submit Information to ERCOT**  **Note 1** | **Model Complete and Available for Test**  **Note 2** | **Updated Network Operations Model Testing Complete**  **Note 3**  **Paragraph (5)** | **Update Network Operations Model Production Environment** | **Target Physical Equipment included in Production Model**  **Note 4** | | --- | --- | --- | --- | --- | | Jan 1 | Feb 15 | March 15 | April 1 | Month of April | | Feb 1 | March 15 | April 15 | May 1 | Month of May | | March 1 | April 15 | May 15 | June 1 | Month of June | | April 1 | May 15 | June 15 | July 1 | Month of July | | May 1 | June 15 | July 15 | August 1 | Month of August | | June 1 | July 15 | August 15 | September 1 | Month of September | | July 1 | August 15 | September 15 | October 1 | Month of October | | August 1 | September 15 | October 15 | November 1 | Month of November | | September 1 | October 15 | November 15 | December 1 | Month of December | | October 1 | November 15 | December 15 | January 1 | Month of January (the next year) | | November 1 | December 15 | January 15 | February 1 | Month of February (the next year) | | December 1 | January 15 | February 15 | March 1 | Month of March (the next year) |   Notes:  1. TSP, DCTO, and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.  2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.  3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.  4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website. |

(4) ERCOT shall only approve energization requests when the Transmission Element is satisfactorily modeled in the Network Operations Model.

(5) Changes to an existing NOMCR that modify only Inter-Control Center Communications Protocol (ICCP) data object names shall be provided 15 days prior to the Network Operations Model load date. NOMCR modifications containing only ICCP data object names shall not be subject to interim update reporting to the Independent Market Monitor (IMM) and Public Utility Commission of Texas (PUCT) (reference Section 3.10.4), according to the following:

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| ***NOMCR that contains ICCP Data and is submitted …*** | ***ERCOT shall …*** | ***Subject to IMM & PUC Reporting*** |
| Beyond 90 days of the energization date | Allow modification of only ICCP data for an existing NOMCR | No |
| Between 90 and 15 days prior to the scheduled database load. | Allow modification of only ICCP data for an existing NOMCR | No |
| Less than 15 days before scheduled database load. | Require a new NOMCR to be submitted containing the ICCP data | Yes |

***3.10.6 Resource Entity Responsibilities***

(1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation Resource, SOG, SOESS, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

**3.10.7.2 Modeling of Resources and Transmission Loads**

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, SOESSs, and Load Resources connected to the transmission system. All Resources greater than ten MW, Generation Resources less than ten MW but providing Ancillary Service, Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), Split Generation Resources where the physical generator being split is greater than ten MW, Private Use Networks containing Resources greater than ten MW, Wind-powered Generation Resources (WGRs), PhotoVoltaic Generation Resources (PVGRs) or Aggregated Generation Resources (AGRs) with an aggregate interconnection to the ERCOT System greater than ten MW, Direct Current Tie (DC Tie) Resources, and the non-TSP owned step-up transformers greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, DC Tie Resources and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

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| ***[NPRR973: Replace paragraph (1) above with the following upon system implementation of PR106:]***  (1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, SOESSs, and Load Resources connected to the transmission system. All Resources greater than ten MW, Generation Resources less than ten MW but providing Ancillary Service, Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage System (SOTESS), Split Generation Resources where the physical generator being split is greater than ten MW, Private Use Networks containing Resources greater than ten MW, Wind-powered Generation Resources (WGRs), PhotoVoltaic Generation Resources (PVGRs) or Aggregated Generation Resources (AGRs) with an aggregate interconnection to the ERCOT System greater than ten MW, Direct Current Tie (DC Tie) Resources, and the non-TSP owned MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, DC Tie Resources and Load Resources with their owners to ensure consistency between TSP models and ERCOT models. |

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| ***[NPRR1016: Replace paragraph (1) above with the following upon system implementation:]***  (1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, SOESSs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), and the non-TSP owned MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models. |

(2) Each Resource Entity representing either a Load Resource or an Aggregate Load Resource (ALR) shall provide ERCOT and, as applicable, its interconnecting DSP and TSP, with information describing each such Resource as specified in Section 3.7.1.2, Load Resource Parameters, and any additional information and telemetry as required by ERCOT, in accordance with the timelines set forth in Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall coordinate the modeling of ALRs with Resource Entities. ERCOT shall coordinate with representatives of the Resource Entity to map Load Resources to their appropriate Load in the Network Operations Model.

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| ***[NPRR1016: Insert paragraph (3) below upon system implementation and renumber accordingly:]***  (3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model. |

(3) Each Resource Entity representing a Distributed Generation (DG) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its registered DG facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered DG facilities to their appropriate Load in the Network Operations Model.

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| ***[NPRR1016: Replace paragraph (3) above with the following upon system implementation:]***  (3) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) or Settlement Only Distribution Energy Storage System (SODESS) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG or SODESS facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG or SODESS facilities to their appropriate Load in the Network Operations Model. |

(4) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Limited Duration Resources, and Energy Storage Resources. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility main power transformer.

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| ***[NPRR973 and NPRR1016: Replace applicable portions of paragraph (4) above with the following upon system implementation of PR106 or upon system implementation, respectively:]***  (4) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Limited Duration Resources, and Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility MPT. |

(5) ERCOT shall create a DC Tie Resource to represent an equivalent generation injection to represent the flow into the ERCOT Transmission Grid from operation of DC Ties. The actual injection flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Resource output.

(6) TSPs shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define “Model Loads”, which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

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| ***[NPRR857: Replace paragraph (6) above with the following upon system implementation:]***  (6) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define “Model Loads”, which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones. |

(7) ERCOT may require TSPs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP shall notify ERCOT if the owner does not comply with the request.

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| ***[NPRR857: Replace paragraph (7) above with the following upon system implementation:]***  (7) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request. |

(8) ERCOT shall create a DC Tie Load to represent an equivalent Load withdrawal to represent the flow from the ERCOT Transmission Grid from operation of DC Ties. The actual withdrawal flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Load output.

(9) Each TSP shall also provide information to ERCOT describing automatic Load transfer (rollover) plans and the events that trigger which Loads are switched to other Transmission Elements on detection of Outage of a primary Transmission Element. ERCOT shall accommodate Load rollover plans in the Network Operations Model

(10) Loads associated with a Generation Resource in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and served through a transformer owned by the Resource Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3.

(11) For purposes of Day-Ahead Market (DAM) Ancillary Services clearing, transmission Outages will be presumed not to affect the availability of any Load Resource for which an offer is submitted. In the event that ERCOT contacts a TSP and confirms that load will not remain connected during a transmission Outage, ERCOT will temporarily override the energization status of the load in DAM to properly reflect the status during the Outage.

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| ***[NPRR1016: Replace paragraph (11) above with the following upon system implementation:]***  (11) If the Day-Ahead Market (DAM) determines, in the processing of Outages, that a Load Resource, DGR, or DESR is de-energized in the ERCOT Network Operations Model, the de-energized Resource will be eligible to receive Ancillary Service awards in the DAM, but will not be eligible to receive energy awards in the DAM. |

(12) A Resource Entity may aggregate Intermittent Renewable Resource (IRR) generation equipment together to form an IRR (WGR or PVGR) if the generation equipment is connected to the same Electrical Bus at the POI and is the same model and size, and the aggregation does not reduce ERCOT’s ability to model pre- and post-contingency conditions. A Resource Entity may also aggregate IRR generation equipment that is not the same model and size together with an existing IRR only if:

(a) The mix of IRR generation equipment models and sizes causes no degradation in the dynamic performance of the IRR represented by the parameters modeled by ERCOT in operational studies and the aggregation of IRR generation equipment does not limit ERCOT’s ability to model the ERCOT Transmission Grid and the relevant contingencies required for monitoring pre- and post-contingency system limits and conditions;

(b) The mix of IRR generation equipment is included in the Resource Registration data submitted for the WGR;

(c) All relevant IRR generation equipment data requested by ERCOT is provided;

(d) With the addition of dissimilar IRR generation equipment, the existing IRR shall continue to meet the applicable Protocol performance requirements, including but not limited to Primary Frequency Response, dynamic capability and Reactive Power capability, at the POI; and

(e) Either:

(i) No more than the lower of 5% or ten MW aggregate capacity is of IRR generation equipment that is not the same model or size from the other equipment within the existing IRR; or

(ii) The wind turbines that are not the same model or size meet the following criteria:

(A) The IRR generation equipment has similar dynamic characteristics to the existing IRR generation equipment, as determined by ERCOT in its sole discretion;

(B) The MW capability difference of each generator is no more than 10% of each generator’s maximum MW rating; and

(C) For WGRs, the manufacturer’s power curves for the wind turbines have a correlation of 0.95 or greater with the other wind turbines within the existing WGR over wind speeds of 0 to 18 m/s.

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| ***[NPRR885 and NPRR1007: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]***  3.14.4 Must-Run Alternative Service  3.14.4.1 Overview and Description of MRAs  (1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.  (2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.  (a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.  (b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.  (c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT’s acceptance of an offer for a Demand Response MRA on ERCOT’s acceptance of an offer for a co-located Other Generation MRA offer.  (d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.  (3) An MRA may be connected at either transmission or distribution voltage.  (4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT’s RMR analysis or in the Load forecasts from the Steady State Working Group base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.  (5) Each MRA must provide at least five MW of capacity.  (6) Eligible MRA resources may include:  (a) A proposed Generation Resource that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.  (i) Proposed Generation Resources must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generation Resource Interconnection or Change Request.  (ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the MRA Contracted Hours.  (b) Proposed capacity additions to existing Generation Resources, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.  (i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary Generator interconnection requirements with respect to this additional capacity.  (ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.  (c) A proposed or existing generator registered, or proposed to be registered, with ERCOT as a Settlement Only Generator (SOG) or as Distributed Generation (DG). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA’s projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.  (d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads.  (e) A proposed or existing Energy Storage System (ESS) registered, or proposed to be registered, with ERCOT as a Settlement Only Energy Storage System (SOESS).  (7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT’s discretion during the MRA Contracted Hours.  (a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA’s temporal constraints.  (b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather–Sensitive MRA.  (8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.  (9) ERCOT will periodically validate an MRA’s telemetry using 15-minute interval meter data.  (10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service.  Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.  (11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, Other Generation MRA, or Demand Response MRA).  (12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.  (13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.  (14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.  (15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.  (16) QSEs must submit the following information for each MRA offer:  (a) The capacity, months and hours offered;  (b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;  (c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;  (d) The MRA Standby Price, represented in dollars per MW per hour;  (e) Required capital expenditure, if any, if the MRA offer is awarded;  (f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;  (g) The ramp period or startup time of the MRA or aggregated MRA;  (h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;  (i) The target availability of the MRA or aggregated MRA; and  (j) Any additional information required by ERCOT within the RFP.  (17) Demand Response MRAs shall not be deployed more than once per Operating Day.  (18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.  (19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource. |

***6.3.2 Activities for Real-Time Operations***

(1) Activities for Real-Time operations begin at the end of the Adjustment Period and conclude at the close of the Operating Hour.

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where “T” represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

| **Operating Period** | **QSE Activities** | **ERCOT Activities** |
| --- | --- | --- |
| During the first hour of the Operating Period |  | Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period  Review the list of Off-Line Available Resources with a start-up time of one hour or less  Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments  Snapshot the Scheduled Power Consumption for Controllable Load Resources |
| Before the start of each SCED run | Update Output Schedules for DSRs | Validate Output Schedules for DSRs  Execute Real-Time Sequence |
| SCED run |  | Execute SCED and pricing run to determine impact of reliability deployments on energy prices |
| During the Operating Hour | Telemeter the Ancillary Service Resource Responsibility for each Resource  Acknowledge receipt of Dispatch Instructions  Comply with Dispatch Instruction    Review Resource Status to assure current state of the Resources is properly telemetered  Update COP with actual Resource Status and limits and Ancillary Service Schedules  Communicate Resource Forced Outages to ERCOT  Communicate to ERCOT Resource changes to Ancillary Service Resource Responsibility via telemetry in the time window beginning 30 seconds prior to the five-minute clock interval and ending ten seconds prior to that five-minute clock interval | Communicate all binding Base Points, Dispatch Instructions, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves, and Real-Time Reserve Price Adders for Off-Line Reserves and LMPs for energy and Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand, total Low Ancillary Service Limit (LASL), total High Ancillary Service Limit (HASL), Real-Time On-Line Reliability Deployment Price Adder using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs)  Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status  Restart Real-Time Sequence on major change of Resource or Transmission Element Status  Monitor ERCOT total system capacity providing Ancillary Services  Validate COP information  Monitor ERCOT control performance  Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves and Real-Time Reserve Price Adders for Off-Line Reserves, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total On-Line LASL, total On-Line HASL, Real-Time On-Line Reliability Deployment Price Adder created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective  Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective  Post on the ERCOT website the projected non-binding LMPs created by each SCED process for each Resource Node, the projected total Real-Time reserve amount for On-Line reserves and Off-Line reserves, the projected Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders, and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, total LASL, total HASL, Real-Time On-Line Reliability Deployment Price Adder and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections  Post on the MIS Certified Area the projected non-binding Base Points for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections  Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs)  Post the Settlement Point Prices for each Settlement Point immediately following the end of each Settlement Interval  Post the Real-Time On-Line Reliability Deployment Price, Real-Time Reserve Price for On-Line Reserves and the Real-Time Reserve Price for Off-Line Reserves immediately following the end of each Settlement Interval  Post parameters as required by Section 6.4.9, Ancillary Services Capacity During the Adjustment Period and in Real-Time, on the ERCOT website |

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| ***[NPRR829, NPRR904, NPRR917, NPRR1000, NPRR1006, NPRR1010: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR829, NPRR904, NPRR917, NPRR1000, or NPRR1006; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]***  (2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where “T” represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:   | **Operating Period** | **QSE Activities** | **ERCOT Activities** | | --- | --- | --- | | During the first hour of the Operating Period |  | Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period  Review the list of Off-Line Available Resources with a start-up time of one hour or less  Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments  Snapshot the Scheduled Power Consumption for Controllable Load Resources | | SCED run |  | Execute SCED and pricing run to determine impact of reliability deployments on energy and Ancillary Service prices | | During the Operating Hour | Acknowledge receipt of Dispatch Instructions  Comply with Dispatch Instruction    Review Resource Status to assure current state of the Resources is properly telemetered  Update COP and telemetry with actual Resource Status and limits and Ancillary Service capabilities  Submit and update Ancillary Service Offers  Communicate Resource Forced Outages to ERCOT | Communicate all binding Base Points, Updated Desired Set Points (UDSPs), Ancillary Service awards, Dispatch Instructions, LMPs for energy, Real-Time MCPCs for Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Transmission and/or Distribution Service Provider (TDSP) standard offer Load management MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs). In communicating Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable.  Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status  Restart Real-Time Sequence on major change of Resource or Transmission Element Status  Monitor ERCOT total system capacity providing Ancillary Services  Validate COP information  Monitor ERCOT control performance  Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and Real-Time MCPCs for each Ancillary Service, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points and Ancillary Service awards from SCED with the time stamp the prices are effective  Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs, Settlement Only Distribution Energy Storage Systems (SODESSs), Settlement Only Transmission Generator (SOTGs), and Settlement Only Transmission Energy Storage Systems (SOTESSs). These prices shall include Real-Time Reliability Deployment Price Adders for Energy created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective  Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective  Post every 15 minutes on the ERCOT website the aggregate net injection from Settlement Only Generators (SOGs) and Settlement Only Energy Storage Systems (SOESSs) that provide Real-Time telemetry to ERCOT, consistent with paragraph (12) of Section 6.5.5.2, Operational Data Requirements. This data shall not be displayed if less than five QSEs or less than 750 megawatts of net injection utilize the option to telemeter Real-Time output for use in the calculation of Real-Time Liability (RTL) as described in Section 16.11.4.3.2, Real-Time Liability Estimate.  Post on the ERCOT website the projected non-binding LMPs for each Resource Node and Real-Time MCPCs for each Ancillary Service created by each SCED process and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, Real-Time Reliability Deployment Price Adder for Energy, Real-Time On-Line Reliability Deployment Price Adders for Ancillary Service, and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections  Post on the MIS Certified Area the projected non-binding Base Points and Ancillary Service awards for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections. In posting Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable.  Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs)  Post on the ERCOT website the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG, SODESS, SOTG, and SOTESS immediately following the end of each Settlement Interval  By Settlement Interval, post the 15-minute Real-Time Reliability Deployment Price for Energy, and the 15-minute Real-Time Reliability Deployment Price for Ancillary Service for each of the Ancillary Services. | |

(3) At the beginning of each hour, ERCOT shall post on the ERCOT website the following information:

(a) Changes in ERCOT System conditions that could affect the security and dynamic transmission limits of the ERCOT System, including:

(i) Changes or expected changes, in the status of Transmission Facilities as recorded in the Outage Scheduler for the remaining hours of the current Operating Day and all hours of the next Operating Day; and

(ii) Any conditions such as adverse weather conditions as determined from the ERCOT-designated weather service;

(b) Updated system-wide Mid-Term Load Forecasts (MTLFs) for all forecast models available to ERCOT Operations, as well as an indicator for which forecast was in use by ERCOT at the time of publication;

(c) The quantities of RMR Services deployed by ERCOT for each previous hour of the current Operating Day; and

(d) Total ERCOT System Demand, from Real-Time operations, integrated over each Settlement Interval.

(4) No later than 0600, ERCOT shall post on the ERCOT website the actual system Load by Weather Zone, the actual system Load by Forecast Zone, and the actual system Load by Study Area for each hour of the previous Operating Day.

(5) ERCOT shall provide notification to the market and post on the ERCOT website Electrical Bus Load distribution factors and other information necessary to forecast Electrical Bus Loads. This report will be published when updates to the Load distribution factors are made. Private Use Network net Load will be redacted from this posting.

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| ***[NPRR1010: Insert paragraphs (6) and (7) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (6) After every SCED run, ERCOT shall post to the ERCOT website the total capability of Resources available to provide the following Ancillary Service combinations, based on the Resource telemetry from the QSE and capped by the limits of the Resource, for the most recent SCED execution:  (a) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;  (b) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;  (c) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;  (d) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;  (e) Capacity to provide Reg-Up, RRS, or both, irrespective of whether it is capable of providing ECRS or Non-Spin;  (f) Capacity to provide Reg-Up, RRS, ECRS, or any combination, irrespective of whether it is capable of providing Non-Spin;  (g) Capacity to provide Reg-Up, RRS, ECRS, Non-Spin, or any combination; and  (h) Capacity to provide Reg-Down.  (7) Each week, ERCOT shall post on the ERCOT website the historical SCED-interval data described in paragraph (6) above. |

**6.5.5.2 Operational Data Requirements**

(1) ERCOT shall use Operating Period data to monitor and control the reliability of the ERCOT Transmission Grid and shall use it in network analysis software to predict the short-term reliability of the ERCOT Transmission Grid. Each TSP, at its own expense, may obtain that Operating Period data from ERCOT or directly from QSEs.

(2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP’s or DSP’s expense, including:

(a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), determination of the High Ancillary Service Limit (HASL), High Dispatch Limit (HDL), Low Dispatch Limit (LDL) and Low Ancillary Service Limit (LASL), and is consistent with telemetered HSL, LSL and Non-Frequency Responsive Capacity (NFRC);

(b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;

(c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) Generation Resource breaker and switch status;

(i) HSL (Combined Cycle Generation Resources) shall:

(i) Submit the HSL of the current operating configuration; and

(ii) When providing RRS, update the HSL as needed, to be consistent with Resource performance limitations of RRS provision;

(j) NFRC currently available (unloaded) and included in the HSL of the Combined Cycle Generation Resource’s current configuration;

(k) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(l) Low Emergency Limit (LEL), under Section 6.5.9.2;

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

(o) Ancillary Service Schedule for each quantity of RRS and Non-Spin which is equal to the Ancillary Service Resource Responsibility minus the amount of Ancillary Service deployment;

(i) For On-line Non-Spin, Ancillary Service Schedule shall be set to zero;

(ii) For Off-Line Non-Spin and for On-Line Non-Spin using Off-Line power augmentation technology the Ancillary Service Schedule shall equal the Non-Spin obligation and then shall be set to zero within 20 minutes following Non-Spin deployment;

(p) Ancillary Service Resource Responsibility for each quantity of Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), RRS and Non-Spin. The sum of Ancillary Service Resource Responsibility for all Resources in a QSE is equal to the Ancillary Service Supply Responsibility for that QSE;

(q) Reg-Up and Reg-Down participation factors represent how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified Resource(s). The Reg-Up and Reg-Down participation factors for a Resource providing Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) shall be zero; and

(r) The designated Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources shall provide Real-Time telemetry for items (a), (b), (c), (d), (e), (g), and (h) above, PSS and AVR status for the total Generation Resource in addition to the Split Generation Resource the Master QSE represents.

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| ***[NPRR863, NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR863, NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]***  (2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP’s or DSP’s expense, including:  (a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), High Dispatch Limit (HDL), and Low Dispatch Limit (LDL), and is consistent with telemetered HSL, LSL, and Frequency Responsive Capacity (FRC);  (b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;  (c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));  (d) Net Reactive Power (in MVAr);  (e) Power to standby transformers serving plant auxiliary Load;  (f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;  (g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;  (h) Generation Resource breaker and switch status;  (i) HSL (Combined Cycle Generation Resources) shall:  (i) Submit the HSL of the current operating configuration; and  (ii) When providing ECRS, update the HSL as needed, to be consistent with Resource performance limitations of ECRS provision;  (j) For Resources with capacity that is not capable of providing Primary Frequency Response (PFR), the current FRC of the Resource;  (k) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;  (l) Low Emergency Limit (LEL), under Section 6.5.9.2;  (m) LSL;  (n) Configuration identification for Combined Cycle Generation Resources;  (o) For Resources with capacity that is not capable of providing PFR, the high and low limits in MW of the Resource’s capacity that is frequency responsive;  (p) For RRS, including any sub-categories of RRS, the physical capability (in MW) of the Resource to provide RRS;  (q) For Ancillary Services other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the physical capability of the Resource to provide that specific type of Ancillary Service;  (r) Five-minute blended Normal Ramp Rates (up and down);  (s) The designated Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources shall provide Real-Time telemetry for items (a), (b), (c), (d), (e), (g), and (h) above, PSS and AVR status for the total Generation Resource in addition to the Split Generation Resource the Master QSE represents; and  (t) The telemetered MW of power augmentation capacity that is not On-Line for Resources that have power augmentation capacity included in HSL. |

(3) For each Intermittent Renewable Resource (IRR), the QSE shall set the HSL equal to the current net output capability of the facility. The net output capability should consider the net real power of the IRR generation equipment, IRR generation equipment availability, weather conditions, and whether the IRR net output is being affected by compliance with a SCED Dispatch Instruction.

(4) For each Aggregate Generation Resource (AGR), the QSE shall telemeter the number of its generators online.

(5) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource’s host TSP or DSP at the TSP’s or DSP’s expense. The Load Resource’s net real power consumption, Low Power Consumption (LPC) and Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a positive (+) sign convention:

(a) Load Resource net real power consumption (in MW);

(b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(c) Load Resource breaker status;

(d) LPC (in MW);

(e) MPC (in MW);

(f) Ancillary Service Schedule (in MW) for each quantity of RRS and Non-Spin, which is equal to the Ancillary Service Resource Responsibility minus the amount of Ancillary Service deployment;

(g) Ancillary Service Resource Responsibility (in MW) for each quantity of Reg-Up and Reg-Down for Controllable Load Resources, and RRS and Non-Spin for all Load Resources;

(h) The status of the high-set under-frequency relay, if required for qualification;

(i) For a Controllable Load Resource providing Non-Spin, the Scheduled Power Consumption that represents zero Ancillary Service deployments;

(j) For a single-site Controllable Load Resource with registered maximum Demand response capacity of ten MW or greater, net Reactive Power (in MVAr);

(k) Resource Status (Resource Status shall be ONRL if high-set under-frequency relay is active);

(l) Reg-Up and Reg-Down participation factor, which represents how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified Resource(s). The Reg-Up and Reg-Down participation factors for a Resource providing FRRS-Up or FRRS-Down shall be zero; and

(m) For a Controllable Load Resource providing Non-Spin, the “Scheduled Power Consumption Plus Two Hours,” representing the QSE’s forecast of the Controllable Load Resource’s instantaneous power consumption for a point two hours in the future.

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| ***[NPRR863, NPRR1010, and NPRR1029: Replace applicable portions of paragraph (5) above with the following upon system implementation for NPRR863 or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]***  (5) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource’s host TSP or DSP at the TSP’s or DSP’s expense. The Load Resource’s net real power consumption, Low Power Consumption (LPC) and Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a positive (+) sign convention:  (a) Load Resource net real power consumption (in MW);  (b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;  (c) Load Resource breaker status;  (d) LPC (in MW);  (e) MPC (in MW);  (f) The Load Resource’s Ancillary Service self-provision (in MW) for RRS and/or ECRS provided via under-frequency relay;  (g) The status of the high-set under-frequency relay, if required for qualification;  (h) For a Controllable Load Resource providing Non-Spin, the Scheduled Power Consumption that represents zero Ancillary Service deployments;  (i) For a single-site Controllable Load Resource with registered maximum Demand response capacity of ten MW or greater, net Reactive Power (in MVAr);  (j) Resource Status;  (k) For a Controllable Load Resource providing Non-Spin, the “Scheduled Power Consumption Plus Two Hours,” representing the QSE’s forecast of the Controllable Load Resource’s instantaneous power consumption for a point two hours in the future;  (l) For RRS, including any sub-categories of RRS, the current physical capability (in MW) of the Resource to provide RRS;  (m) For Ancillary Service products other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the current physical capability of the Resource’s ability to provide a particular Ancillary Service product; and  (n) For a Controllable Load Resource, 5-minute blended Normal Ramp Rates (up and down). |

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| ***[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (6) below upon system implementation and renumber accordingly:]***  (6) A QSE representing an ESR connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each ESR. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP’s or DSP’s expense, including:  (a) Net real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process. Net real power represents the actual generation or consumption of an ESR for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), in determination of High Dispatch Limit (HDL), and Low Dispatch Limit (LDL) and is consistent with telemetered HSL, LSL and Frequency Responsive Capacity (FRC);  (b) Gross real power consumption or output (in MW) as measured by installed power metering or as calculated in accordance with the Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversion constants determined by the Resource Entity and provided to ERCOT through the Resource Registration process;  (c) Gross Reactive Power (in Megavolt-Amperes reactive (MVAr));  (d) Net Reactive Power (in MVAr);  (e) Power to standby transformers serving plant auxiliary Load;  (f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;  (g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;  (h) ESR breaker and switch status;  (i) HSL;  (j) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;  (k) Low Emergency Limit (LEL), under Section 6.5.9.2;  (l) LSL;  (m) For RRS, including any sub-category of RRS, the current physical capability (in MW) of the Resource to provide RRS;  (n) For Ancillary Services other than RRS, a blended ramp rate (in MW/min) that reflects the current physical capability of the Resource to provide that specific type of Ancillary Service; and  (o) Five-minute blended normal up and down ramp rates; |

(6) A QSE with Resources used in SCED shall provide communications equipment to receive ERCOT-telemetered control deployments.

(7) A QSE providing any Regulation Service shall provide telemetry indicating the appropriate status of Resources providing Reg-Up or Reg-Down, including status indicating whether the Resource is temporarily blocked from receiving Reg-Up and/or Reg-Down deployments from the QSE. This temporary blocking will be indicated by the enabling of the Raise Block Status and/or Lower Block Status telemetry points.

(a) Raise Block Status and Lower Block Status are telemetry points used in transient unit conditions to communicate to ERCOT that a Resource’s ability to adjust its output has been unexpectedly impaired.

(b) When one or both of the telemetry points are enabled for a Resource, ERCOT will cease using the regulation capacity assigned to that Resource for Ancillary Service deployment.

(c) This hiatus of deployment will not excuse the Resource’s obligation to provide the Ancillary Services for which it has been committed.

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| ***[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]***  (c) This hiatus of deployment will not excuse the Resource’s obligation to provide the Ancillary Services for which it has been awarded. |

(d) These telemetry points shall only be utilized during unforeseen transient unit conditions such as plant equipment failures. Raise Block Status and Lower Block Status shall only be enabled until the Resource operator has time to update the Resource limits and Ancillary Service telemetry to reflect the problem.

(e) The Resource limits and Ancillary Service telemetry shall be updated as soon as practicable.  Raise Block Status and Lower Block Status will then be disabled.

(8) Real-Time data for reliability purposes must be accurate to within three percent. This telemetry may be provided from relaying accuracy instrumentation transformers.

(9) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT. The telemetered Resource Status for a Combined Cycle Generation Resource may only be assigned a Resource Status of OFFNS if no generation units within that Combined Cycle Generation Resource are On-Line.

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| ***[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]***  (9) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT. The telemetered Resource Status for a Combined Cycle Generation Resource may only be assigned a Resource Status of OFF if no generation units within that Combined Cycle Generation Resource are On-Line. |

(10) A QSE representing Combined Cycle Generation Resources shall provide ERCOT with the possible operating configurations for each power block with accompanying limits. Combined Cycle Train power augmentation methods may be included as part of one or more of the registered Combined Cycle Generation Resource configurations. Power augmentation methods may include:

(a) Combustion turbine inlet air cooling methods;

(b) Duct firing;

(c) Other ways of temporarily increasing the output of Combined Cycle Generation Resources; and

(d) For Qualifying Facilities (QFs), an LSL that represents the minimum energy available for Dispatch by SCED, in MW, from the Combined Cycle Generation Resource based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

(11) A QSE representing Generation Resources other than Combined Cycle Generation Resources may telemeter an NFRC value for their Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT’s approval of the Generation Resource’s NFRC quantity.

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| ***[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (11) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]***  (11) A QSE representing a Generation Resource other than a Combined Cycle Generation Resource may provide FRC telemetry for the Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT’s approval. |

(12) A QSE representing an Energy Storage Resource (ESR) shall provide the following Real-Time telemetry data to ERCOT for each ESR:

(a) Maximum Operating State of Charge, in MWh;

(b) Minimum Operating State of Charge, in MWh;

(c) State of Charge, in MWh;

(d) Maximum Operating Discharge Power Limit, in MW; and

(e) Maximum Operating Charge Power Limit, in MW.

(13) In accordance with ERCOT Protocols, NERC Reliability Standards, and Governmental Authority requirements, ERCOT shall make the data specified in paragraph (12) available to any requesting TSP or DSP at the requesting TSP’s or DSP’s expense.

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| ***[NPRR829: Insert paragraph (14) below upon system implementation:]***  (14) A QSE representing a Settlement Only Generator (SOG) that elects to include the net generation of the SOG in the estimate of Real-Time Liability (RTL) shall provide ERCOT Real-Time telemetry of the net generation of the SOG. |

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| ***[NPRR885: Insert paragraph (15) below upon system implementation:]***  (15) A QSE representing a Must-Run Alternative (MRA) shall telemeter the MRA MW currently available (unloaded) and not included in the HSL. |

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| ***[NPRR1029: Insert paragraph (16) below upon system implementation:]***  (16) A QSE representing a DC-Coupled Resource shall provide the following Real-Time telemetry data in addition to that required for other Energy Storage Resources (ESRs):  (a) Gross AC MW production of the intermittent renewable generation component of the DC-Coupled Resource, which includes the portion of the intermittent renewable generation used to charge the Energy Storage System (ESS) and/or serve auxiliary Load on the DC side of the inverter; and  (b) Gross AC MW capability of the intermittent renewable generation component of the DC-Coupled Resource, based on Real-Time conditions. |

(17) A QSE representing a Settlement Only Energy Storage System (SOESS) that elects to include the net generation and/or net withdrawals of the SOESS in the estimate of Real-Time Liability (RTL) shall provide ERCOT Real-Time telemetry of the net generation and/or net withdrawals of the SOESS.

***6.5.9.4.2 EEA Levels***

(1) ERCOT will declare an EEA Level 1 when PRC falls below 2,300 MW and is not projected to be recovered above 2,300 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 1:

(a) ERCOT shall take the following steps to maintain steady state system frequency near 60 Hz and maintain PRC above 1,750 MW:

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

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

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

(iv) At ERCOT’s discretion, deploy available contracted ERS-30 via an XML message followed by a VDI to the all-QSE Hotline. The ERS-30 ramp period shall begin at the completion of the VDI.

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| ***[NPRR998: Replace item (iv) above with the following upon system implementation:]***  (iv) At ERCOT’s discretion, deploy available contracted ERS-30 via an XML message followed by a VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been deployed. The ERS-30 ramp period shall begin at the completion of the VDI. |

(A) If less than 500 MW of ERS-30 is available for deployment, ERCOT shall deploy it as a single block.

(B) If the amount of ERS-30 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-30 as a single block or by group designation. ERCOT shall develop a random selection methodology for determining how to place ERS Resources in ERS-30 into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS Contract Period for ERS-30, ERCOT shall notify QSEs representing ERS Resources in ERS-30 of their ERS Resources’ group assignments.

(C) ERS-30 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct their ERS Resources in ERS-30 to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, until either ERCOT releases the ERS-30 deployment or the ERS-30 Resources have reached their maximum deployment time.

(E) ERCOT shall notify QSEs of the release of ERS-30 via an XML message followed by VDI to the all-QSE Hotline. The VDI shall represent the official notice of ERS-30 release. ERCOT may release ERS-30 as a block or by group designation.

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| ***[NPRR998: Replace item (E) above with the following upon system implementation:]***  (E) ERCOT shall notify QSEs of the release of ERS-30 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been recalled. The VDI shall represent the official notice of ERS-30 release. ERCOT may release ERS-30 as a block or by group designation. |

(F) Upon release, an ERS Resource in ERS-30 shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the release.

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| ***[NPRR1010: Insert paragraph (v) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (v) At ERCOT’s discretion, manually deploy, through ICCP, available RRS and ECRS capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS. |

(b) QSEs shall:

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

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| ***[NPRR1010: Replace paragraph (i) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (i) Ensure COPs and telemetered HSLs, Normal Ramp Rates, Emergency Ramp Rates, and Ancillary Service capabilities are updated and reflect all Resource delays and limitations; and |

(ii) Suspend any ongoing ERCOT required Resource performance testing.

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| ***[NPRR1002: Insert paragraph (iii) below upon system implementation:]***  (iii) Ensure that each of its ESRs and SOESSs suspends charging until the EEA is recalled, except under the following circumstances:  (A) The ESR has a current SCED Base Point Instruction, Load Frequency Control Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;  (B) The ESR or SOESS is actively providing Primary Frequency Response; or  (C) The ESR or SOESS is co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained. |

(2) ERCOT may declare an EEA Level 2 when the clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT will declare an EEA Level 2 when PRC falls below 1,750 MW and is not projected to be recovered above 1,750 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

(a) In addition to the measures associated with EEA Level 1, ERCOT shall take the following steps to maintain steady state system frequency at a minimum of 59.91 Hz and maintain PRC above 1,430 MW:

(i) Instruct TSPs and DSPs or their agents to reduce Customer Load by using distribution voltage reduction measures, if deemed beneficial by the TSP, DSP, or their agents.

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

(iii) Instruct QSEs to deploy available contracted ERS-10 Resources, undeployed ERS-30 and/or deploy RRS supplied from Load Resources (controlled by high-set under-frequency relays). ERCOT may deploy ERS-10, ERS-30, or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above.

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| ***[NPRR863: Replace item (iii) above with the following upon system implementation:]***  (iii) Instruct QSEs to deploy available contracted ERS-10 Resources, undeployed ERS-30, and/or deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ERS-10, ERS-30, ECRS, or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above. |

(iv) ERCOT shall deploy ERS-10 via an XML message followed by a VDI to the all-QSE Hotline. The ERS-10 ramp period shall begin at the completion of the VDI.

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| ***[NPRR998: Replace item (iv) above with the following upon system implementation:]***  (iv) ERCOT shall deploy ERS-10 via an XML message followed by a VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been deployed. The ERS-10 ramp period shall begin at the completion of the VDI. |

(A) If less than 500 MW of ERS-10 is available for deployment, ERCOT shall deploy all ERS-10 Resources as a single block.

(B) If the amount of ERS-10 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-10 Resources as a single block or by group designation. ERCOT shall develop a random selection methodology for determining how to place ERS-10 Resources into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS-10 Contract Period, ERCOT shall notify QSEs representing ERS-10 Resources of their ERS-10 Resources’ group assignments.

(C) ERS-10 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct ERS-10 Resources to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4 until ERCOT releases the ERS-10 deployment or the ERS-10 Resources have reached their maximum deployment times.

(E) ERCOT shall notify QSEs of the release of ERS-10 via an XML message followed by VDI to the all-QSE Hotline. The VDI shall represent the official notice of ERS-10 release. ERCOT may release ERS-10 as a block or by group designation.

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| ***[NPRR998: Replace item (E) above with the following upon system implementation:]***  (E) ERCOT shall notify QSEs of the release of ERS-10 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been recalled. The VDI shall represent the official notice of ERS-10 release. ERCOT may release ERS-10 as a block or by group designation. |

(F) Upon release, an ERS-10 Resource shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the release.

(v) ERCOT shall deploy RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

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| ***[NPRR863: Replace paragraph (v) above with the following upon system implementation:]***  (v) Load Resources providing ECRS that are not controlled by high set under-frequency relays shall be deployed prior to Group 1 deployment. ERCOT shall deploy ECRS and RRS capacity supplied by Load Resources (controlled by high set under-frequency relays) in accordance with the following: |

(A) Instruct QSEs to deploy half of the RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 1 Load Resources providing RRS. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from Group 2 if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

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| ***[NPRR863 and NPRR939: Replace applicable portions of paragraph (A) above with the following upon system implementation:]***  (A) Instruct QSEs to deploy RRS with a Group 1 designation and all of the ECRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resources to interrupt Group 1 Load Resources providing ECRS and RRS. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from any of the groups not designated for deployment if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; |

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy the remaining RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 2 Load Resources providing RRS. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

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| ***[NPRR939: Replace paragraph (B) above with the following upon system implementation:]***  (B) At the discretion of the ERCOT Operator, instruct QSEs to deploy RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt additional Load Resources providing RRS based on their group designation. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; |

(C) The ERCOT Operator may deploy both of the groups of Load Resources providing RRS at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; and

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| ***[NPRR863 and NPRR939: Replace applicable portions of paragraph (C) above with the following upon system implementation:]***  (C) The ERCOT Operator may deploy Load Resources providing only ECRS (not controlled by high-set under-frequency relays) and all groups of Load Resources providing RRS and ECRS at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; and |

(D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource obligation which may be deployed to interrupt under paragraph (A), Group 1 and paragraph (B), Group 2. ERCOT shall develop a process for determining which individual Load Resource to place in Group 1 and which to place in Group 2. ERCOT procedures shall select Group 1 and Group 2 based on a random sampling of individual Load Resources. At ERCOT’s discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

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| ***[NPRR939 and NPRR1010: Replace applicable portions of paragraph (D) above with the following upon system implementation for NPRR939; and upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]***  (D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource RRS or ECRS award, which may be deployed to interrupt under paragraph (A) and paragraph (B). ERCOT shall develop a process for determining which individual Load Resource to place in each group based on a random sampling of individual Load Resources. At ERCOT’s discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2. |

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

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

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

(3) ERCOT may declare an EEA Level 3 when the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes. ERCOT will declare an EEA Level 3 when PRC cannot be maintained above 1,430 MW or when the clock-minute average system frequency falls below 59.91 Hz for 25 consecutive minutes. Upon declaration of an EEA Level 3, ERCOT will implement any measures associated with EEA Levels 1 and 2 that have not already been implemented.

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| ***[NPRR1002: Insert paragraph (a) below upon system implementation and renumber accordingly:]***  (a) ERCOT shall instruct ESRs and SOESSs to suspend charging. For ESRs, ERCOT shall issue the instruction via a SCED Base Point, or, if otherwise necessary, via a manual Dispatch instruction. An ESR or SOESS shall suspend charging unless providing Primary Frequency Response or LFC issues a charging instruction to an ESR that is carrying Reg-Down. However, an ESR or SOESS co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained. |

(a) When PRC falls below 1,000 MW and is not projected to be recovered above 1,000 MW within 30 minutes, or when the clock-minute average frequency falls below 59.91 Hz for 25 consecutive minutes, ERCOT shall direct all TSPs and DSPs or their agents to shed firm Load, in 100 MW blocks, distributed as documented in the Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover 1,000 MW of PRC within 30 minutes.

(b) In addition to measures associated with EEA Levels 1 and 2, TSPs and DSPs or their agents 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, TSPs and DSPs or their agents shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

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

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

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

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

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

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

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

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

(g) Its AML at the Settlement Point; plus

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| [NPRR986 and NPRR1043: Replace item (g) above with the following upon system implementation of NPRR986:]  (g) Its AML at the Settlement Point excluding Non-WSL ESR Charging Load; plus |

(h) The aggregated generation of its Settlement Only Generators (SOGs) in the Load Zone.

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| ***[NPRR917: Replace item (h) above with the following upon system implementation:]***  (h) The aggregated generation of its Settlement Only Transmission Self-Generators (SOTSGs) at the Settlement Point. SOTSG sites will be represented as a single unit in the ERCOT Settlement system.  (i) The aggregated generation of its Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that have elected to retain Load Zone pricing in accordance with Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS). SODG, SOTG, SODESS and SOTESS sites will be represented as a single unit in the ERCOT Settlement system. |

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

**RTEIAMT *q, p* = (-1) \* {[RTSPP *p* \* [(SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼)]] + [RTSPPEW *p* \* (RTMGNM *q, p* – RTAML *q, p*)]}**

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| ***[NPRR917 and NPRR986: Replace applicable portions of the formula “RTEIAMT q, p” above with the following upon system implementation:]***  **RTEIAMT *q, p* = (-1) \* {[RTSPP *p* \* [(SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼)]] + [RTSPPEW *p* \* (RTMGSOGZ *q, p* – (RTAML *q, p* – RTAMLESRNW *q, p* – RTAMLNWSOL *q, p*))]}** |

And

**LZIMBAL *q, p =* (SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼) – RTAML *q, p* + RTMGNM *q, p***

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| ***[NPRR917 and NPRR986: Replace applicable portions of the formula “LZIMBAL q, p” above with the following upon system implementation:]***  **LZIMBAL *q, p =* (SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼) – (RTAML *q, p* –RTAMLESRNW *q, p* – RTAMLNWSOL *q, p*) + RTMGSOGZ *q, p*** |

The above variables are defined as follows:

| **Variable** | **Unit** | **Description** |
| --- | --- | --- |
| RTEIAMT *q, p* | $ | *Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval. |
| RTSPP *p* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval. |
| LZIMBAL *q, p* | MWh | *Load Zone Energy Imbalance per QSE per Settlement Point*—The Load Zone volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval. |
| RTSPPEW *p* | $/MWh | *Real-Time Settlement Point Price Energy-Weighted*⎯The Real-Time Settlement Point Price at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the State Estimated Load for the Load Zone of each SCED interval within the 15-minute Settlement Interval. |
| RTAML *q, p* | MWh | *Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval. |
| |  |  |  |  | | --- | --- | --- | --- | | [NPRR986 and NPRR1043: Insert the variable “RTAMLESRNW q, p” below upon system implementation of NPRR986:]   |  |  |  | | --- | --- | --- | | RTAMLESRNW *q, p* | MWh | *Real-Time Adjusted Metered Load for ESR Non-WSL per QSE per Settlement Point*—The sum of the AML for the Non-WSL ESR Charging Load at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value. | | | | |
| RTAMLNWSOL *q, p* | MWh | *Real-Time Adjusted Metered Load for Non-WSL Settlement Only* *Charging Load per QSE per Settlement Point*—The sum of the AML for the Non-WSL Settlement Only Charging Load for the SODESS or SOTESS site that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value. |
| SSSK *q, p* | MW | *Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*’s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval. |
| DAEP *q, p* | MW | *Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*’s DAM Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval. |
| RTQQEP *q, p* | MW | *Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*⎯The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval. |
| SSSR *q, p* | MW | *Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*’s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval. |
| DAES *q, p* | MW | *Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*’s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval. |
| RTQQES *q, p* | MW | *Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*⎯The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval. |
| RTMGNM *q, p* | MWh | *Real-Time Metered Generation from Settlement Only Generators per QSE per Settlement Point*—The total Real-Time energy produced by SOGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. |
| |  |  |  |  | | --- | --- | --- | --- | | ***[NPRR917: Replace the variable “RTMGNM q, p” above with the following upon system implementation:]***   |  |  |  | | --- | --- | --- | | RTMGSOGZ *q, p* | MWh | *Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by SOTSGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for SODGs and SOTGs that have opted out of nodal pricing pursuant to Section 6.6.3.9 will also be included in this value. | | | | |
| *q* | none | A QSE. |
| *p* | none | A Load Zone Settlement Point. |

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

**RTEIAMTQSETOT *q* = RTEIAMT *q, p***

The above variables are defined as follows:

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

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| ***[NPRR917 and NPRR1010: Insert applicable portions of Section 6.6.3.9 below upon system implementation for NPRR917; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]***  **6.6.3.9 Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS)**  (1) Except for a SODG or SOTG that has opted out of nodal pricing as described in paragraph (5) below, the payment or charge to each QSE for energy from an SODG, SOTG, SODESS, or SOTESS shall be based on an identified nodal energy price, RTESOPR, as described in this subsection.  (2) For an SODG or an SODESS, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus associated with this mapped Load in the Network Operations Model. For an SOTG or an SOTESS, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus as determined by ERCOT in review of the meter location of the SOTG or SOTESS in the Network Operations Model. The outflow of energy into the grid as measured by each Settlement Meter for the 15-minute Settlement Interval for an SODG, SOTG, SODESS, or SOTESS site shall be priced at the nodal energy price. Wholesale Storage Load (WSL) and Non-WSL Settlement Only Charging Load for an SODESS or SOTESS site shall be settled at the nodal energy price. Load that is not WSL will be included in the Real-Time AML per QSE. Each SODG, SOTG, SODESS, and SOTESS site will be represented as a single unit in the ERCOT Settlement system.  (3) For an SODG, SOTG, SODESS, or SOTESS, the total payment or charge for each 15-minute Settlement Interval shall be calculated as follows:  **RTGSOAMT *q,* *gsc* = (-1) \* [( RTESOPR *b* \* OFSOG *q, gsc, b*)]**  **RTWSLSOAMT *q, gsc* = (-1) \* [( RTESOPR *b* \* WSOL *q, gsc, b*)]**  **RTNWSLSOAMT *q, gsc*= (-1) \* [( RTESOPR *b* \* NWSOL *q, gsc, b*)]**  **Where the price for the SOTG, SODG, SODESS, or SOTESS is determined as follows:**  **RTESOPR *b* = Max [-$251, ((SDWF *y* \* RTLMP *b, y*) + RTRDP)]**  Where:    RTRDP = (SDWF *y* \* RTRDPA *y*)  SDWF *y* = TLMP *y* / TLMP *y*  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTGSOAMT*q,**gsc* | $ | *Real-Time Generation for SODG, SOTG, SODESS, or SOTESS Site Amount* —The total payment or charge for generation to QSE *q* for SODG, SOTG, SODESS, or SOTESS site *gsc* for the 15-minute Settlement Interval. | | RTWSLSOAMT*q,**gsc* | $ | *Real-Time WSL for SODESS or SOTESS Site Amount* —The total payment or charge for WSL to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval. | | RTNWSLSOAMT*q,**gsc* | $ | *Real-Time Non-WSL for SODESS or SOTESS Site Amount* —The total payment or charge for Non-WSL Settlement Only Charging Load to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval. | | RTESOPR *b* | $/MWh | *Real-Time Price for the Energy Metered for each SODG, SOTG, SODESS, or SOTESS Site* ⎯The Real-Time price at Electrical Bus *b* for the Settlement Meter for the SODG, SOTG, SODESS*,* or SOTESS site for the 15-minute Settlement Interval. | | OFSOG *q,* *gsc, b* | MWh | *Outflow as Measured for an SODG, SOTG, SODESS, or SOTESS* *Site* ⎯The outflow as measured by the Settlement Meter(s) at Electrical Bus *b* for SODG, SOTG, SODESS*,* orSOTESS site *gsc* represented by QSE *q* for the 15-minute Settlement Interval. | | WSOL *q, gsc, b* | MWh | *WSL for an SODESS or SOTESS Site -* The WSL as measured for an SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by QSE *q,* represented as a negative value, for the 15-minute Settlement Interval. | | NWSOL *q, gsc, b* | MWh | *Non-WSL Settlement Only Charging Load for an SODESS or SOTESS Site -* The Non-WSL Settlement Only Charging Load as measured for an SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by QSE *q,* represented as a negative value, for the 15-minute Settlement Interval. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy* ⎯The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA*y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy* ⎯The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*. | | SDWF *y* | None | *SCED Duration Weighting Factor per interval*⎯The weight used in the SODG, SOTG, SODESS, or SOTESS price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | RTLMP *b, y* | $/MWh | *Real-Time Locational Marginal Price at bus per interval*⎯The Real-Time LMP at Electrical Bus *b*, for the SCED interval *y*. | | TLMP *y* | second | *Duration of SCED interval per interval*⎯The duration of the SCED interval *y* within the Settlement Interval. | | *gsc* | none | A generation site code. | | *b* | none | An Electrical Bus. | | *y* | None | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. |   (4) The total net payments and charges to each QSE for energy from SODGs, SOTGs, SODESS, or SOTESS for the 15-minute Settlement Interval is calculated as follows:  **RTESOAMTQSETOT *q* = (RTGSOAMT *q, gsc* +RTWSLSOAMT *q, gsc*+ RTNWSLSOAMT *q, gsc*)**The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | RTESOAMTQSETOT *q* | $ | *Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESS, or SOTESS* —The payment or charge to QSE *q* for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval. | | RTGSOAMT *q, gsc* | $ | *Real-Time Generation for SODG, SOTG, SODESS, or SOTESS Site Amount* —The total payment or charge for generation to QSE *q* for SODG, SOTG, SODESS, or SOTESS site *gsc* for the 15-minute Settlement Interval. | | RTWSLSOAMT*q,**gsc* | $ | *Real-Time WSL for SODESS or SOTESS Site Amount* —The total payment or charge for WSL to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval. | | RTNWSLSOAMT*q,**gsc* | $ | *Real-Time Non-WSL for SODESS or SOTESS Site Amount* —The total payment or charge for Non-WSL Settlement Only Charging Load to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval. | | *q* | none | A QSE. | | *gsc* | none | A generation site code. |   (5) Notwithstanding anything else in this Section except paragraphs (6) and (7) below, a Resource Entity may opt out of nodal pricing and continue Load Zone Settlement for any SODG or SOTG if, by January 1, 2019, the SODG or SOTG was operational or was subject to a Power Purchase or Tolling Agreement (PPA) or Transmission and/or Distribution Service Provider (TDSP) interconnection agreement, or had an executed agreement with a developer. By December 31, 2019, the Resource Entity must submit a properly completed Section 23, Form N, Pricing Election for Settlement Only Distribution Generators and Settlement Only Transmission Generators. Any SODG or SOTG relying on a PPA or TDSP interconnection agreement or agreement with a developer must also have achieved Initial Synchronization for the full Resource capacity before June 1, 2020 to be eligible to opt out of nodal pricing. A Resource Entity must provide ERCOT documented proof of any PPA, TDSP interconnection agreement, or developer agreement that it relies on as a basis for any election under this paragraph. This election is valid through the earlier of December 31, 2029 or the date on which the election is revoked pursuant to paragraph (8) of this Section. On January 1, 2030, all SODGs and SOTGs will be subject to nodal pricing.  (6) For any SODG or SOTG for which the applicable Resource Entity has elected to opt out of nodal pricing, ERCOT shall settle the output of the SODG or SOTG using the Load Zone Settlement Point Price for the duration of the opt-out period so long as the SODG or SOTG is not physically modified for any purpose, including to increase the capacity of the unit or change the fuel type of the unit, except as necessary for routine maintenance or repairs to address normal wear and tear.  (7) If at any time ERCOT determines that the SODG or SOTG fails to meet the opt-out conditions in paragraph (6) above, ERCOT shall settle the output of the SODG or SOTG at the applicable nodal price as soon as practicable after providing written notice to the affected Resource Entity.  (8) A Resource Entity that has opted out of nodal pricing for one or more SODGs or SOTGs pursuant to paragraph (5) of this Section may withdraw that election and begin receiving applicable nodal pricing for one or more such generators by submitting a properly completed election form (Section 23, Form N). An election of nodal pricing is irrevocable. ERCOT will effectuate the transition of an SODG or SOTG to nodal pricing in ERCOT Settlement systems as soon as practicable. |

***6.6.10 Real-Time Revenue Neutrality Allocation***

(1) ERCOT must be revenue-neutral in each Settlement Interval. Each QSE receives an allocated share, on a LRS basis, of the net amount of:

(a) Real-Time Energy Imbalance payments or charges under Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(b) Real-Time Energy Imbalance payments or charges under Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

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

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

(e) Real-Time energy payments under Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(f) Real-Time energy charge under Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;

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| ***[NPRR917: Insert item (g) below upon system implementation and renumber accordingly:]***  (g) Real-Time Energy payments or charges under Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS); |

(g) Real-Time congestion payments or charges under Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules; and

(h) Real-Time payments or charges to the Congestion Revenue Right (CRR) Owners under Section 7.9.2, Real-Time CRR Payments and Charges.

(2) The Real-Time Revenue Neutrality Allocation for each QSE for a given 15-minute Settlement Interval is calculated as follows:

**LARTRNAMT *q* = (-1) \* (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTDCEXPAMTTOT + RTCCAMTTOT + RTOBLAMTTOT / 4 + RTOBLLOAMTTOT / 4) \* LRS *q***

|  |
| --- |
| ***[NPRR917: Replace the formula “LARTRNAMT q” above with the following upon system implementation:]***  **LARTRNAMT *q* = (-1) \* (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTDCEXPAMTTOT + RTESOGAMTTOT + RTCCAMTTOT + RTOBLAMTTOT / 4 + RTOBLLOAMTTOT / 4) \* LRS *q*** |

Where:

Total Real-Time Energy Imbalance Payment (or Charge) at Settlement Point (or Hub)

RTEIAMTTOT = RTEIAMTQSETOT *q*

Total Real-Time Payment for BLT Resources

BLTRAMTTOT = BLTRAMTQSETOT *q*

Total Real-Time Payment for DC Tie Imports

RTDCIMPAMTTOT = RTDCIMPAMTQSETOT *q*

Total Real-Time Charge for DC Tie Exports (under “Oklaunion Exemption”)

RTDCEXPAMTTOT = RTDCEXPAMTQSETOT *q*

Total Real-Time Congestion Payment or Charge for Self-Schedules

RTCCAMTTOT = RTCCAMTQSETOT *q*

Total Real-Time Payment or Charge for Point-to-Point (PTP) Obligations

RTOBLAMTTOT = RTOBLAMTQSETOT *q*

Total Real-Time Payment for PTP Obligations with Links to Options

RTOBLLOAMTTOT = RTOBLLOAMTQSETOT *q*

|  |
| --- |
| ***[NPRR917: Insert the language below upon system implementation:]***  Total Real-Time Payment or Charge for energy from SODGs and SOTGs  RTESOGAMTTOT =  RTESOGAMTQSETOT *q* |

The above variables are defined as follows:

| **Variable** | **Unit** | **Description** |
| --- | --- | --- |
| LARTRNAMT *q* | $ | *Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*’s share of the total Real-Time revenue neutrality amount, for the 15-minute Settlement Interval. |
| RTEIAMTTOT *q* | $ | *Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance Service at all Settlement Points (Resource, Load Zone or Hub) for the 15-minute Interval. |
| BLTRAMTTOT | $ | *Block Load Transfer Resource Amount Total*⎯The total of payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval. |
| RTDCIMPAMTTOT | $ | *Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval. |
| RTDCEXPAMTTOT | $ | *Real-Time DC Export Amount Total*—The summation of charges to all QSEs under the “Oklaunion Exemption” for DC Tie exports for the 15-minute Settlement Interval. |
| RTCCAMTTOT | $ | *Real-Time Energy Congestion Cost Amount Total*—The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval. |
| RTOBLAMTTOT | $ | *Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval. |
| RTOBLLOAMTTOT | $ | *Real-Time Obligation with Links to an Option Amount Total*—The sum of all payments for PTP Obligations with Links to an Option settled in Real-Time for the hour that includes the 15-minute Settlement Interval. |
| RTEIAMTQSETOT *q* | $ | *Real-Time Energy Imbalance Amount QSE Total per QSE*⎯The total net payments and charges to QSE *q* for Real-Time Energy Imbalance at all Resource Node Settlement Points for the 15-minute Settlement Interval. |
| RTCCAMTQSETOT *q* | $ | *Real-Time Congestion Cost Amount QSE Total per QSE*⎯The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval. |
| BLTRAMTQSETOT *q* | $ | *Block Load Transfer Resource Amount QSE Total per QSE*⎯The total of the payments to QSE *q* for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval. |
| RTDCIMPAMTQSETOT *q* | $ | *Real-Time DC Import Amount QSE Total per QSE*⎯The total of the payments to QSE *q* for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval. |
| RTDCEXPAMTQSETOT *q* | $ | *Real-Time DC Export Amount QSE Total per QSE*⎯The total of the charges to QSE *q* for energy exported from the ERCOT Region through DC Ties for the 15-minute Settlement Interval. |
| RTOBLAMTQSETOT q | $ | *Real-Time Obligation Amount QSE Total per QSE*—The net total payment or charge to QSE *q* of all its PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time. |
| RTOBLLOAMTQSETOT *q* | $ | *Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The total payment to QSE *q* for all of its PTP Obligations with Links to an Option settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.1. |
| |  |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | --- | | ***[NPRR917: Insert the variables “RTESOGAMTQSETOT q” and “RTESOGAMTTOT” below upon system implementation:]***   |  |  |  | | --- | --- | --- | | RTESOGAMTQSETOT *q* | $ | *Real-Time Energy Payment or Charge per QSE for Energy from SODGs and SOTGs* —The payment or charge to QSE *q* for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval. | | RTESOGAMTTOT | $ | *Real-Time Energy Amount Total for Energy from all SODGs and SOTGs* —The total net payments and charges to all QSEs for Real-Time energy from SODGs and SOTGs, for the 15-minute Settlement Interval. | | | | |
| LRS *q* | none | The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval. |
| *q* | none | A QSE. |
| *o* | none | A CRR owner. |

(3) In the event that ERCOT is unable to execute the DAM, the Real-Time Revenue Neutrality Allocation for each QSE for a given 15-minute Settlement Interval is calculated as follows:

**LARTRNAMT *q* = (-1) \* (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTDCEXPAMTTOT + RTCCAMTTOT + NDRTOBLAMTTOT / 4 + NDRTOPTAMTTOT / 4 + NDRTOPTRAMTTOT / 4 + NDRTOBLRAMTTOT / 4) \* LRS *q***

|  |
| --- |
| ***[NPRR917: Replace the formula “LARTRNAMT q” above with the following upon system implementation:]***  **LARTRNAMT *q* = (-1) \* (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTDCEXPAMTTOT + RTESOAMTTOT + RTCCAMTTOT + NDRTOBLAMTTOT / 4 + NDRTOPTAMTTOT / 4 + NDRTOPTRAMTTOT / 4 + NDRTOBLRAMTTOT / 4) \* LRS *q*** |

Where:

Total Real-Time Energy Imbalance Payment (or Charge) at Settlement Point (or Hub)

RTEIAMTTOT = RTEIAMTQSETOT *q*

Total Real-Time Payment for BLT Resources

BLTRAMTTOT = BLTRAMTQSETOT *q*

Total Real-Time Payment for DC Tie Imports

RTDCIMPAMTTOT = RTDCIMPAMTQSETOT *q*

Total Real-Time Charge for DC Tie Exports (under “Oklaunion Exemption”)

RTDCEXPAMTTOT = RTDCEXPAMTQSETOT *q*

Total Real-Time Congestion Payment or Charge for Self Schedules

RTCCAMTTOT = RTCCAMTQSETOT *q*

Total Real-Time Payment or Charge for PTP Obligations when ERCOT is unable to execute the DAM

NDRTOBLAMTTOT =  NDRTOBLAMTOTOT *o*

Total Real-Time Payment for PTP Options when ERCOT is unable to execute the DAM

NDRTOPTAMTTOT =  NDRTOPTAMTOTOT *o*

Total Real-Time Payment for PTP Options with Refund when ERCOT is unable to execute the DAM

NDRTOPTRAMTTOT = NDRTOPTRAMTOTOT *o*

Total Real-Time Payment or Charge for PTP Obligations with Refund when ERCOT is unable to execute the DAM

NDRTOBLRAMTTOT =  NDRTOBLRAMTOTOT *o*

|  |
| --- |
| ***[NPRR917: Insert the language below upon system implementation:]***  Total Real-Time Payment or Charge for energy from SODGs, SOTGs, SODESSs, or SOTESSs  RTESOAMTTOT = RTESOAMTQSETOT *q* |

The above variables are defined as follows:

| **Variable** | **Unit** | **Description** |
| --- | --- | --- |
| LARTRNAMT *q* | $ | *Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*’s share of the total Real-Time revenue neutrality amount for the 15-minute Settlement Interval. |
| RTEIAMTTOT | $ | *Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance at all Settlement Points (Resource, Load Zone, or Hub) for the 15-minute Interval. |
| BLTRAMTTOT | $ | *Block Load Transfer Resource Amount Total*⎯The total of the payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval. |
| RTDCIMPAMTTOT | $ | *Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval. |
| RTDCEXPAMTTOT | $ | *Real-Time DC Export Amount Total*—The summation of charges to all QSEs that are under the “Oklaunion Exemption” for DC Tie exports for the 15-minute Settlement Interval. |
| RTCCAMTTOT | $ | *Real-Time Energy Congestion Cost Amount Total*—The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval. |
| NDRTOBLAMTTOT | $ | *No DAM Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval. |
| NDRTOPTAMTTOT | $ | *No DAM Real-Time Option Amount Total*—The sum of all payments for PTP Options settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval. |
| NDRTOPTRAMTTOT | $ | *No DAM Real-Time Option with Refund Amount Total*—The sum of all payments for PTP Options with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval. |
| NDRTOBLRAMTTOT | $ | *No DAM Real-Time Obligation with Refund Amount Total*— The sum of all payments for PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval. |
| RTEIAMTQSETOT *q* | $ | *Real-Time Energy Imbalance Amount QSE Total per QSE*⎯The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval. |
| RTCCAMTQSETOT *q* | $ | *Real-Time Congestion Cost Amount QSE Total per QSE*⎯The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval. |
| BLTRAMTQSETOT *q* | $ | *Block Load Transfer Resource Amount QSE Total per QSE*⎯The total of the payments to QSE *q* for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval. |
| RTDCIMPAMTQSETOT *q* | $ | *Real-Time DC Import Amount QSE Total per QSE*⎯The total of the payments to QSE *q* for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval. |
| RTDCEXPAMTQSETOT *q* | $ | *Real-Time DC Export Amount QSE Total per QSE*⎯The total of the charges to QSE *q* for energy exported from the ERCOT Region through DC Ties for the 15-minute Settlement Interval. |
| NDRTOBLAMTOTOT *o* | $ | *No DAM Real-Time Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* of all its PTP Obligations settled in Real-Time when ERCOT is unable to execute the DAM, for the hour. |
| NDRTOPTAMTOTOT *o* | $ | *No DAM Real-Time Option Amount Owner Total per CRR Owner*—The total payment to CRR owner *o* for all its PTP Options settled in Real-Time when ERCOT is unable to execute the DAM, for the hour. |
| NDRTOPTRAMTOTOT *o* | $ | *No DAM Real-Time Option with Refund Amount Owner Total per CRR Owner*—The total payment to NOIE CRR owner *o* for all its PTP Options with Refund settled in Real-Time when ERCOT is unable to execute the DAM, for the hour. |
| NDRTOBLRAMTOTOT *o* | $ | *No DAM Real-Time Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* for all its PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour. |
| |  |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | --- | | [NPRR917: Insert the variables “RTESOAMTQSETOT q” and “RTESOAMTTOT” below upon system implementation:]   |  |  |  | | --- | --- | --- | | RTESOAMTQSETOT *q* | $ | *Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESSs, or SOTESSs* —The payment or charge to QSE *q* for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval. | | RTESOAMTTOT | $ | *Real-Time Energy Amount Total from all SODGs, SOTGs, SODESSs, or SOTESSs* —The total net payments and charges to all QSEs for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval. | | | | |
| LRS *q* | none | The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval. |
| *q* | none | A QSE. |
| *o* | none | A CRR Owner. |

**8.1.1.4.2 Responsive Reserve Energy Deployment Criteria**

(1) Each QSE providing RRS shall so indicate by appropriate entries in the Resource’s Ancillary Service Schedule and the Ancillary Service Resource Responsibility providing that service. When manually deployed as specified in Nodal Operating Guide Section 4.8, Responsive Reserve Service During Scarcity Conditions, SCED shall adjust the Generation Resource’s Base Point for any requested RRS energy in the next cycle of SCED as specified in Section 6.5.7.6.2.2, Deployment of Responsive Reserve Service. For Controllable Load Resources, the QSE shall control its Resources to operate to the Resource’s Scheduled Power Consumption minus any Ancillary Service deployments. Control performance during periods in which RRS has been self-deployed shall be based on the requirements below and failure to meet any one of these requirements may be reported to the Reliability Monitor as non-compliance:

(a) Within one minute following a deployment instruction, the QSE must update the telemetered Ancillary Service Schedule for RRS for Generation Resources and Load Resources to reflect the deployment amount. The difference between the sum of the QSE’s Resource RRS schedules and the sum of the QSE’s Resource RRS responsibilities must be equal to the QSE’s total RRS deployment instruction, excluding the deployment to Load Resources which are not Controllable Load Resources.

(b) A QSE providing RRS must reserve sufficient PFR capable capacity on each Generation Resource with a RRS responsibility or must reserve sufficient capacity capable of FFR to supply the full amount of RRS scheduled for that Resource. The QSE shall not use NFRC, such as power augmentation capacity on a Generation Resource, to provide RRS.

(c) ERCOT shall evaluate the Primary Frequency Response of all RRS providers as calculated in Nodal Operating Guide Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response.

(2) For all Frequency Measurable Events (FMEs), ERCOT shall use the recorded data for each two-second scan rate value of real power output for each Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), Settlement Only Transmission Energy Storage System (SOTESS), Resource capable of FFR providing RRS, and Controllable Load Resource. ERCOT shall use the recorded MW data beginning one minute before the start of the frequency excursion event until ten minutes after the start of the frequency excursion event. Satisfactory performance for those Resources with a RRS responsibility must be measured by comparing actual Primary Frequency Response to the expected Primary Frequency Response as required in the Operating Guides.

(3) ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Generation Resources, SOTGs, SOTSGs, SOTESSs, Resources capable of FFR, and Controllable Load Resources with RRS responsibilities using the methodology specified in the Operating Guides. ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Controllable Load Resources, relay response for Loads and Generation Resources operating in the synchronous condenser fast-response mode providing RRS at the frequency specified in paragraph (3)(b) of Section 3.18, Resource Limits in Providing Ancillary Service.

(4) For QSEs with Load Resources, excluding Controllable Load Resources, ten minutes following deployment instruction the sum of the QSE’s Load Resource response shall not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:

(i) The QSE’s Responsibility for RRS from non-Controllable Load Resources; or

(ii) The requested MW deployment.

The QSE’s portfolio shall maintain this response until recalled or the Resource’s obligation to provide RRS expires. The combination of the QSE’s RRS responsibility and additional available capacity shall not exceed 150% of the sum of the QSE’s Ancillary Service Resource Responsibility for RRS from non-Controllable Load Resources. Any additional available capacity from Load Resources other than Controllable Load Resources shall be deployed concurrently with RRS.

(5) For Load Resources, excluding Controllable Load Resources, associated with a QSE that does not successfully deploy as defined under this Section, ERCOT shall evaluate, identify and investigate each Load Resource that contributed to such failure, in order to determine failure under paragraph (9) of Section 8.1.1.1, Ancillary Service Qualification and Testing.

(6) A Load Resource providing RRS excluding Controllable Load Resources must return to at least 95% of its Ancillary Service Resource Responsibility for RRS within three hours following a recall instruction unless replaced by another Resource as described below. However, the Load Resource should attempt to return to at least 95% of its Ancillary Service Resource Responsibility for RRS as soon as practical considering process constraints. For a Load Resource that is not a Controllable Load Resource that is unable to return to its Ancillary Service Resource Responsibility within three hours of recall instruction, its QSE may replace the quantity of deficient RRS capacity within that same three hours using other Generation Resources or other Load Resources not previously committed to provide RRS.

(7) During periods when the Load level of a Load Resource (excluding Controllable Load Resources) has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource’s actual Load response from its Baseline. “Baseline” capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

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| [NPRR863 and NPRR1011: Replace applicable portions of Section 8.1.1.4.2 above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]  **8.1.1.4.2 Responsive Reserve Energy Deployment Criteria**  (1) Control performance during periods in which RRS has been self-deployed shall be based on the requirements below and failure to meet any one of these requirements may be reported to the Reliability Monitor as non-compliance:  (a) A QSE providing RRS must reserve sufficient Primary Frequency Response capable capacity on each Generation Resource with a RRS award or must reserve sufficient capacity capable of FFR to supply the full amount of RRS awarded to that Resource. The QSE shall not use non-FRC, such as power augmentation capacity on a Generation Resource, to provide RRS.  (b) ERCOT shall evaluate the Primary Frequency Response of all RRS providers as calculated in Nodal Operating Guide Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response.  (2) For all Frequency Measurable Events (FMEs), ERCOT shall use the recorded data for each two-second scan rate value of real power output for each Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), Resource capable of FFR providing RRS, and Controllable Load Resource. ERCOT shall use the recorded MW data beginning one minute before the start of the frequency excursion event until ten minutes after the start of the frequency excursion event. Satisfactory performance for those Resources with an RRS award must be measured by comparing actual Primary Frequency Response to the expected Primary Frequency Response as required in the Operating Guides.  (3) ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Generation Resources, SOTGs, SOTSGs, SOTESSs, Resources capable of FFR, and Controllable Load Resources with RRS responsibilities using the methodology specified in the Operating Guides. ERCOT shall monitor the Primary Frequency Response that is delivered during FMEs of Controllable Load Resources, relay response for Loads and Generation Resources operating in the synchronous condenser fast-response mode providing RRS at the frequency specified in paragraph (3)(b) of Section 3.18, Resource Limits in Providing Ancillary Service.  (4) For Resources providing FFR, once the FFR is deployed, the Resource must stay deployed for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurs first. A Load Resource that is controlled by a high-set under-frequency relay and is providing FFR may only withdraw energy from the grid after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, or if instructed to do so by ERCOT.  (5) For a Resource providing RRS with a Resource Status of ONSC, once the RRS is deployed, the Resource must maintain the response until recalled by ERCOT.  (6) For a Load Resource that is controlled by a high-set under-frequency relay and is providing RRS, once the RRS is deployed, the Resource must maintain the response to the deployment until recalled by ERCOT.  (7) For QSEs with Load Resources, excluding Controllable Load Resources, ten minutes following deployment instruction the sum of the QSE’s Load Resource response shall not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:  (i) The QSE’s award for RRS from non-Controllable Load Resources; or  (ii) The requested MW deployment.  The QSE’s portfolio shall maintain this response until recalled.  (8) For Load Resources, excluding Controllable Load Resources, associated with a QSE that does not successfully deploy as defined under this Section, ERCOT shall evaluate, identify and investigate each Load Resource that contributed to such failure, in order to determine failure under paragraph (9) of Section 8.1.1.1, Ancillary Service Qualification and Testing.  (9) For a QSE self-providing RRS on Load Resources, excluding Controllable Load Resources that have been deployed for RRS, the QSE may move the self-provided amount to another Load Resource, while maintaining the deployment instructions on the previously deployed Load Resource, if:  (a) The Load Resource to which the RRS is to be moved is not a Controllable Load Resource and has not been deployed for RRS; and  (b) The self-provided amount of RRS is within the QSE’s portfolio.  (10) During periods when the Load level of a Load Resource (excluding Controllable Load Resources) has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource’s actual Load response from its Baseline. “Baseline” capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction. |

**8.5.1.1 Governor in Service**

(1) At all times a Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) is On-Line, its Governor must remain in service and be allowed to respond to all changes in system frequency except during startup, shutdown, or testing. A Generation Entity may not reduce Primary Frequency Response on an individual Generation Resource, Settlement Only Generator (SOG), or Settlement Only Energy Storage System (SOESS) even during abnormal conditions without ERCOT’s consent (conveyed by way of the Resource Entity’s Qualified Scheduling Entity (QSE)) unless equipment damage is imminent. All Generation Resources, SOTGs, SOTSGs, and SOTESSs that have capacity available to either increase or decrease output or withdrawal in Real-Time must provide Primary Frequency Response, which may make use of that available capacity. Only Generation Resources providing Regulation Up (Reg-Up), Regulation Down (Reg-Down), Responsive Reserve (RRS), or Non-Spinning Reserve (Non-Spin) from On-Line Resources, as specified in Section 8.1.1, QSE Ancillary Service Performance Standards, shall be required to reserve capacity that may also be used to provide Primary Frequency Response.

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| ***[NPRR863 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]***  (1) At all times a Generation Resource, Energy Storage Resource (ESR), Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) is On-Line, its Governor must remain in service and be allowed to respond to all changes in system frequency except during startup, shutdown, or testing. A Resource Entity may not reduce Primary Frequency Response on an individual Generation Resource, ESR, Settlement Only Generator (SOG), or SOTESS even during abnormal conditions without ERCOT’s consent (conveyed by way of the Resource Entity’s Qualified Scheduling Entity (QSE)) unless equipment damage is imminent. All Generation Resources, ESRs, SOTGs, SOTSGs, and SOTESSs that have capacity available to either increase output or decrease output in Real-Time must provide Primary Frequency Response, which may make use of that available capacity. Only Generation Resources or ESRs providing Responsive Reserve (RRS), Regulation Up (Reg-Up), Regulation Down (Reg-Down), ERCOT Contingency Reserve Service (ECRS), or Non-Spinning Reserve (Non-Spin) from On-Line Resources, as specified in Section 8.1.1, QSE Ancillary Service Performance Standards, shall be required to reserve capacity that may also be used to provide Primary Frequency Response. |

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| [NPRR863, NPRR989, and NPRR1011: Insert applicable portions of paragraph (2) below upon system implementation for NPRR863 and NPRR989; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]  (2) Generation Resources and ESRs that do not have an RRS or Regulation Service Ancillary Service award shall set their Governor Dead-Band no greater than ±0.036 Hz from nominal frequency of 60 Hz. A Generation Resource or ESR that widens its Governor Dead-Band greater than what is prescribed in Nodal Operating Guide Section 2.2.7, Turbine Speed Governors, must update its Resource Registration data with the new dead-band value. |

(3) SOTGs, SOTSGs, and SOTESSs shall set their Governor Dead-Band no greater than ±0.036 Hz from nominal frequency of 60 Hz.

**8.5.1.2 Reporting**

(1) Each Resource Entity shall conduct applicable Governor tests on each of its Generation Resources as specified in the Operating Guides. The Resource Entity shall provide test results and other relevant information to ERCOT. ERCOT shall make these results available to the Transmission Service Providers (TSPs).

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| ***[NPRR963 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]***  (1) Each Resource Entity shall conduct applicable Governor tests on each of its Generation Resources and ESRs as specified in the Operating Guides. The Resource Entity shall provide test results and other relevant information to ERCOT. ERCOT shall make these results available to the Transmission Service Providers (TSPs). |

(2) Generation Resource Governor modeling information required in the ERCOT planning criteria must be determined from actual Generation Resource testing described in the Operating Guides. Within 30 days of ERCOT’s request, the results of the latest test performed must be supplied to ERCOT and the connected TSP.

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| ***[NPRR989: Replace paragraph (2) above with the following upon system implementation:]***  (2) Generation Resource and ESR Governor modeling information required in the ERCOT planning criteria must be determined from actual Generation Resource or ESR testing described in the Operating Guides. Within 30 days of ERCOT’s request, the results of the latest test performed must be supplied to ERCOT and the connected TSP. |

(3) Each QSE shall inform ERCOT as soon as practical when notified by its On-Line Generation Resource, SOTG, SOTSG, or SOTESS of the Governor being out-of-service. The QSE shall supply related logs to ERCOT upon request.

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| ***[NPRR989: Replace paragraph (3) above with the following upon system implementation:]***  (3) Each QSE shall inform ERCOT as soon as practical when notified by its On-Line Generation Resource, ESR, SOTG, SOTSG, or SOTESS of the Governor being out-of-service. The QSE shall supply related logs to ERCOT upon request. |

(4) If a Generation Resource trips Off-Line during a disturbance, as defined by the North American Electric Reliability Corporation (NERC), while providing Primary Frequency Response, the QSE shall report the cause of the failure to ERCOT as soon as the cause has been identified.

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| ***[NPRR989: Replace paragraph (4) above with the following upon system implementation:]***  (4) If a Generation Resource or ESR trips Off-Line during a disturbance, as defined by the North American Electric Reliability Corporation (NERC), while providing Primary Frequency Response, the QSE shall report the cause of the failure to ERCOT as soon as the cause has been identified. |

***8.5.2 Primary Frequency Response Measurements***

(1) ERCOT, with the assistance of the appropriate Technical Advisory Committee (TAC) subcommittee, shall analyze the performance of Generation Resources, SOTGs, SOTSGs, SOTESSs, Resources capable of Fast Frequency Response (FFR), and Controllable Load Resources for all Frequency Measurable Events (FMEs) in accordance with the Operating Guides. In support of this analysis, ERCOT shall post the following:

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| ***[NPRR963 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]***  (1) ERCOT, with the assistance of the appropriate Technical Advisory Committee (TAC) subcommittee, shall analyze the performance of Generation Resources, ESRs, SOTGs, SOTSGs, SOTESSs, Resources capable of Fast Frequency Response (FFR), and Controllable Load Resources for all Frequency Measurable Events (FMEs) in accordance with the Operating Guides. In support of this analysis, ERCOT shall post the following: |

(a) ERCOT shall post on the ERCOT website the occurrence of an FME within 14 calendar days of occurrence.

(b) ERCOT shall post on the Market Information System (MIS) Certified Area for Performance, Disturbance, Compliance Working Group (PDCWG) analysis, the Primary Frequency Response Unit Performance for each Generation Resource, SOTG, SOTSG, SOTESS, and Controllable Load Resource that is measured in the FME.

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| ***[NPRR963 and NPRR989: Replace applicable portions of paragraph (b) above with the following upon system implementation:]***  (b) ERCOT shall post on the MIS Certified Area for Performance, Disturbance, Compliance Working Group (PDCWG) analysis, the Primary Frequency Response Unit Performance for each Generation Resource, ESR, SOTG, SOTSG, SOTESS, and Controllable Load Resource that is measured in the FME. |

(c) ERCOT shall post on the ERCOT website a monthly report that displays the frequency response of the ERCOT System for a rolling average of the last six FMEs.

(d) ERCOT shall post on the ERCOT website an annual report that displays the minimum frequency response computation methodology of the ERCOT System.

(e) ERCOT shall post on the MIS Certified Area the Primary Frequency Response 12-month rolling average for each Generation Resource, SOTG, SOTSG, SOTESS, Resource capable of FFR, and Controllable Load Resource.

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| ***[NPRR963 and NPRR989: Replace applicable portions of paragraph (e) above with the following upon system implementation:]***  (e) ERCOT shall post on the MIS Certified Area the Primary Frequency Response 12-month rolling average for each Generation Resource, ESR, SOTG, SOTSG, SOTESS, Resource capable of FFR, and Controllable Load Resource. |

**8.5.2.1 ERCOT Required Primary Frequency Response**

(1) All Generation Resources, SOTGs, SOTSGs, SOTESS, Resources capable of FFR, and Controllable Load Resources shall provide Primary Frequency Response in accordance with the requirements established in the Operating Guides.

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| ***[NPRR963 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]***  (1) All Generation Resources, ESRs, SOTGs, SOTSGs, SOTESS, and Controllable Load Resources shall provide Primary Frequency Response in accordance with the requirements established in the Operating Guides. |

(2) ERCOT shall evaluate, with the assistance of the appropriate TAC subcommittee, Primary Frequency Response during FMEs. The actual Generation Resource response must be compiled to determine if adequate Primary Frequency Response was provided.

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| ***[NPRR963 and NPRR989: Replace applicable portions of paragraph (2) above with the following upon system implementation:]***  (2) ERCOT shall evaluate, with the assistance of the appropriate TAC subcommittee, Primary Frequency Response during FMEs. The actual Generation Resource or ESR response must be compiled to determine if adequate Primary Frequency Response was provided. |

(3) ERCOT and the appropriate TAC subcommittee shall review each FME, verifying the accuracy of data. Data that is in question may be requested from the QSE for comparison or individual Generation Resource data may be retrieved from ERCOT’s database.

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| ***[NPRR963 and NPRR989: Replace applicable portions of paragraph (3) above with the following upon system implementation:]***  (3) ERCOT and the appropriate TAC subcommittee shall review each FME, verifying the accuracy of data. Data that is in question may be requested from the QSE for comparison or individual Resource data may be retrieved from ERCOT’s database. |

***9.5.3 Real-Time Market Settlement Charge Types***

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement “Charge Types” are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section [5.7.5, RUC Clawback Payment](#_Toc109528011);

(g) Section [5.7.6, RUC Decommitment Charge](#_Toc109528014);

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

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

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

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Payment;

(o) Section 6.6.3.8, Real-Time High Dispatch Limit Override Energy Charge;

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

(q) Section 6.6.5.1.1.1, Base Point Deviation Charge for Over Generation;

(r) Section 6.6.5.1.1.2, Base Point Deviation Charge for Under Generation;

(s) Section 6.6.5.2, IRR Generation Resource Base Point Deviation Charge;

(t) Section 6.6.5.4, Base Point Deviation Payment;

(u) Section 6.6.6.1, RMR Standby Payment;

(v) Section 6.6.6.2, RMR Payment for Energy;

(w) Section 6.6.6.3, RMR Adjustment Charge;

(x) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(y) Section 6.6.6.5, RMR Service Charge;

(z) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(aa) Paragraph (2) of Section 6.6.7.1, Voltage Support Service Payments;

(bb) Paragraph (4) of Section 6.6.7.1;

(cc) Section 6.6.7.2, Voltage Support Charge;

(dd) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(ee) Section 6.6.8.2, Black Start Capacity Charge;

(ff) Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT;

(gg) Section 6.6.9.2, Charge for Emergency Power Increases;

(hh) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(ii) Paragraph (1)(a) of Section 6.7.1, Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Services Market (SASM) or Reconfiguration Supplemental Ancillary Services Market (RSASM);

(jj) Paragraph (1)(b) of Section 6.7.1;

(kk) Paragraph (1)(c) of Section 6.7.1;

(ll) Paragraph (1)(d) of Section 6.7.1;

(mm) Paragraph (1)(a) of Section 6.7.2, Payments for Ancillary Service Capacity Assigned in Real-Time Operations;

(nn) Paragraph (1)(b) of Section 6.7.2;

(oo) Paragraph (1)(a) of Section 6.7.2.1, Charges for Infeasible Ancillary Service Capacity Due to Transmission Constraints;

(pp) Paragraph (1)(b) of Section 6.7.2.1;

(qq) Paragraph (1)(c) of Section 6.7.2.1;

(rr) Paragraph (1)(d) of Section 6.7.2.1;

(ss) Paragraph (1)(a) of Section 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide;

(tt) Paragraph (1)(b) of Section 6.7.3;

(uu) Paragraph (1)(c) of Section 6.7.3;

(vv) Paragraph (1)(d) of Section 6.7.3;

(ww) Paragraph (2) of Section 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement;

(xx) Paragraph (3) of Section 6.7.4;

(yy) Paragraph (4) of Section 6.7.4;

(zz) Paragraph (5) of Section 6.7.4;

(aaa) Paragraph (7) of Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge (Real-Time Ancillary Service Imbalance Amount);

(bbb) Paragraph (7) of Section 6.7.5, (Real-Time Reliability Deployment Ancillary Service Imbalance Amount);

(ccc) Paragraph (8) of Section 6.7.5, (Real-Time RUC Ancillary Service Reserve Amount);

(ddd) Paragraph (8) of Section 6.7.5, (Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount);

(eee) Section 6.7.6, Real Time Ancillary Service Imbalance Revenue Neutrality Allocation (Load-Allocated Ancillary Service Imbalance Revenue Neutrality Amount);

(fff) Section 6.7.6, (Load-Allocated Reliability Deployment Ancillary Service Imbalance Revenue Neutrality Amount);

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

(hhh) Section 9.16.1, ERCOT System Administration Fee.

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| ***[NPRR841, NPRR863, NPRR885, NPRR917, NPRR963, NPRR1012, and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR841, NPRR863, NPRR885, NPRR963, or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]***  (1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement “Charge Types” are:  (a) Section 5.7.1, RUC Make-Whole Payment;  (b) Section 5.7.2, RUC Clawback Charge;  (c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;  (d) Section 5.7.4.1, RUC Capacity-Short Charge;  (e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;  (f) Section [5.7.5, RUC Clawback Payment](#_Toc109528011);  (g) Section [5.7.6, RUC Decommitment Charge](#_Toc109528014);  (h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;  (i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;  (j) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;  (k) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;  (l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;  (m) Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;  (n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Payment;  (o) Section 6.6.3.8, Real-Time High Dispatch Limit Override Energy Charge;  (p) Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS);  (q) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules;  (r) Section 6.6.5.1.1.1, Set Point Deviation Charge for Over Generation;  (s) Section 6.6.5.1.1.2, Set Point Deviation Charge for Under Generation;  (t) Section 6.6.5.1.1.3, Controllable Load Resource Set Point Deviation Charge for Over Consumption;  (u) Section 6.6.5.1.1.4, Controllable Load Resource Set Point Deviation Charge for Under Consumption;  (v) Section 6.6.5.2, IRR Generation Resource Set Point Deviation Charge;  (w) Section 6.6.5.3, Controllable Load Resource Set Point Deviation Charge for Over Consumption;  (x) Section 6.6.5.3.1, Controllable Load Resource Set Point Deviation Charge for Under Consumption;  (y) Section 6.6.5.4, Set Point Deviation Payment;  (z) Section 6.6.5.5, Energy Storage Resource Set Point Deviation Charge for Over Performance;  (aa) Section 6.6.5.5.1, Energy Storage Resource Set Point Deviation Charge for Under Performance;  (bb) Section 6.6.6.1, RMR Standby Payment;  (cc) Section 6.6.6.2, RMR Payment for Energy;  (dd) Section 6.6.6.3, RMR Adjustment Charge;  (ee) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;  (ff) Section 6.6.6.5, RMR Service Charge;  (gg) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;  (hh) Section 6.6.6.7, MRA Standby Payment;  (ii) Section 6.6.6.8, MRA Contributed Capital Expenditures Payment;  (jj) Section 6.6.6.9, MRA Payment for Deployment Event;  (kk) Section 6.6.6.10, MRA Variable Payment for Deployment;  (ll) Section 6.6.6.11, MRA Charge for Unexcused Misconduct;  (mm) Section 6.6.6.12, MRA Service Charge;  (nn) Paragraph (3) of Section 6.6.7.1, Voltage Support Service Payments;  (oo) Paragraph (5) of Section 6.6.7.1;  (pp) Section 6.6.7.2, Voltage Support Charge;  (qq) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;  (rr) Section 6.6.8.2, Black Start Capacity Charge;  (ss) Section 6.6.9.1, Payment for Emergency Operations Settlement;  (tt) Section 6.6.9.2, Charge for Emergency Operations Settlement;  (uu) Section 6.6.10, Real-Time Revenue Neutrality Allocation;  (vv) Section 6.6.11.1, Emergency Response Service Capacity Payments;  (ww) Section 6.6.11.2, Emergency Response Service Capacity Charge;  (xx) Section 6.7.4, Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations;  (yy) Section 6.7.5.2, Regulation Up Service Payments and Charges;  (zz) Section 6.7.5.3, Regulation Down Service Payments and Charges;  (aaa) Section 6.7.5.4, Responsive Reserve Payments and Charges;  (bbb) Section 6.7.5.5 , Non-Spinning Reserve Payments and Charges;  (ccc) Section 6.7.5.6 , ERCOT Contingency Reserve Service Payments and Charges;  (ddd) Section 6.7.5.7 , Real-Time Derated Ancillary Service Capability Payment;  (eee) Section 6.7.5.8 , Real-Time Derated Ancillary Service Capability Charge;  (fff) Section 6.7.6, Real Time Ancillary Service Revenue Neutrality Allocation;  (ggg) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time; and  (hhh) Section 9.16.1, ERCOT System Administration Fee. |

(2) In the event that ERCOT is unable to execute the Day-Ahead Market (DAM), ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for the following RTM Congestion Revenue Right (CRR) Settlement charges and payments:

(a) Section 7.9.2.4, Payments for FGRs in Real-Time; and

(b) Section 7.9.2.5, Payments and Charges for PTP Obligations with Refund in Real-Time.

***9.17.1 Billing Determinant Data Elements***

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

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

(b) The ERCOT average 4-CP;

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

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

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

(4) Any difference between the coincidental MW peak (converted to MWh) and the ERCOT Settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE’s Load, and WSL, shall be allocated amongst all DSPs and ELSEs that are included in the ERCOT 4-CP Report on a pro rata basis as per the formula below:

**LTDSP\_4CP *tdsp* = (PLTDSP4CPLRS t*dsp* \* NLADJ) + PLTDSP4CP *tdsp***

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| LTDSP\_4CP *tdsp* | MWh | *Load by TDSP for 4-CP* - The load for each DSP and ELSE coincident to the coincidental MW peak adjusted for NLADJ |
| PLTDSP4CPLRS *tdsp* | % | *Preliminary Load by TDSP for 4-CP Load Ratio Share* -The Load Ratio Share (LRS) for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ |
| NLADJ | MWh | *Native Load Adjustment* - The difference between the coincidental MW peak (converted to MWh) and the ERCOT settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE’s Load, and WSL |
| PLTDSP4CP *tdsp* | MWh | *Preliminary Load by TDSP for 4CP* -The Load for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ |
| *tdsp* | None | A DSP or ELSE |

***9.19.1 Default Uplift Invoices***

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

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

**DURSCP*cp* = TSPA \* MMARS*cp***

Where:

MMARS *cp* = MMA *cp* / MMATOT

MMA *cp* = Max { ∑*mp* (URTMG *mp*+ URTDCIMP *mp*),

∑*mp* (URTAML *mp* + UWSLTOT *mp*),

∑*mp*URTQQES *mp*,

∑*mp* URTQQEP *mp*,

∑*mp* UDAES *mp*,

∑*mp* UDAEP *mp*,

∑*mp* (URTOBL *mp +* URTOBLLO *mp*),

∑*mp* (UDAOPT *mp*+ UDAOBL *mp*+UOPTS *mp*+UOBLS *mp*),

∑*mp* (UOPTP *mp*+ UOBLP *mp*)}

|  |
| --- |
| ***[NPRR917 and NPRR1012: Replace applicable portions of the formula “MMA cp” above with the following upon system implementation for NPRR917; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]***  MMA *cp* = Max { ∑*mp* (URTMG *mp*+ URTDCIMP *mp* + USOGTOT *mp*),  ∑*mp* (URTAML *mp* + UWSLTOT *mp* + USOCLTOT *mp*),  ∑*mp*URTQQES *mp*,  ∑*mp* URTQQEP *mp*,  ∑*mp* UDAES *mp*,  ∑*mp* UDAEP *mp*,  ∑*mp* (URTOBL *mp +* URTOBLLO *mp*),  ∑*mp* (UDAOPT *mp*+ UDAOBL *mp*+UOPTS *mp*+UOBLS *mp*),  ∑*mp* (UOPTP *mp*+ UOBLP *mp*),  ∑*mp*  UDAASOAWD *mp*} |

MMATOT = ∑*cp* (MMA*cp*)

Where:

URTMG *mp* = ∑*p, r, i* (RTMG *mp, p, r, i*), excluding RTMG for RMR Resources and RTMG in Reliability Unit Commitment (RUC)-Committed Intervals for RUC-committed Resources

URTDCIMP *mp* = ∑*p, i* (RTDCIMP *mp, p, i*) / 4

URTAML *mp* = max(0,∑*p, i* (RTAML *mp, p, i*))

URTQQES *mp* = ∑*p, i* (RTQQES *mp, p, i*) / 4

URTQQEP *mp* = ∑*p, i* (RTQQEP *mp, p, i*) / 4

UDAES *mp* = ∑*p, h* (DAES *mp, p, h*)

UDAEP *mp* = ∑*p, h* (DAEP *mp, p, h*)

URTOBL *mp* = ∑*(j, k), h* (RTOBL*mp, (j, k), h*)

URTOBLLO *mp* = ∑*(j, k), h* (RTOBLLO*mp, (j, k), h*)

UDAOPT *mp* = ∑*(j, k), h* (DAOPT*mp, (j, k), h*)

UDAOBL *mp* = ∑*(j, k), h* (DAOBL*mp, (j, k), h*)

UOPTS *mp* = ∑*(j, k), h* (OPTS*mp, (j, k), h*)

UOBLS *mp* = ∑*(j, k), h* (OBLS*mp, (j, k), h*)

UOPTP *mp* = ∑*(j, k), h* (OPTP*mp, j, h*)

UOBLP *mp* = ∑*(j, k), h* (OBLP*mp, (j, k), h*)

UWSLTOT *mp* = (-1) \* ∑*r, b* (MEBL *mp, r, b*)

|  |
| --- |
| ***[NPRR1012: Insert the formula “UDAASOAWD mp” below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  UDAASOAWD *mp*  = ∑*h* ( DARUOAWD *mp,h* + DARDOAWD *mp,h* + DARROAWD *mp,h* + DANSOAWD *mp,h* + DAECROAWD *mp, h* ) |

|  |
| --- |
| ***[NPRR917: Insert the formula “USOGTOT mp” and “USOCLTOT mp” below upon system implementation:]***  USOGTOT *mp* = ∑*gsc, b* (OFSOG *mp, gsc, b*) + ∑ *p, i* (RTMGSOGZ *mp, p, i*)  USOCLTOT *mp* = (-1) \* ∑*gsc, b* (WSOL *mp, gsc, b* + NWSOL *mp, gsc, b*) |

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| DURSCP *cp* | $ | *Default Uplift Ratio Share per Counter-Party*—The Counter-Party’s pro rata portion of the total short-pay amount for all Day-Ahead Market (DAM) and Real-Time Market (RTM) Invoices for a month. |
| TSPA | $ | *Total Short Pay Amount*—The total short-pay amount calculated by ERCOT to be collected through the Default Uplift Invoice process. |
| MMARS *cp* | None | *Maximum MWh Activity Ratio Share*—The Counter-Party’s pro rata share of Maximum MWh Activity. |
| MMA *cp* | MWh | *Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction for a month. |
| MMATOT | MWh | *Maximum MWh Activity Total*—The sum of all Counter-Party’s Maximum MWh Activity. |
| RTMG *mp, p, r, i* | MWh | *Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| URTMG *mp* | MWh | *Uplift Real-Time Metered Generation per Market Participant*—The monthly sum of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTDCIMP *mp, p, i* | MW | *Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| URTDCIMP *mp* | MW | *Uplift Real-Time DC Import per Market Participant*—The monthly sum of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party. |
| RTAML *mp, p, i* | MWh | *Real-Time Adjusted Metered Load per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML) at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| URTAML *mp* | MWh | *Uplift Real-Time Adjusted Metered Load per Market Participant*—The monthly sum of the AML represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTQQES *mp, p, i* | MW | *QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| URTQQES *mp* | MWh | *Uplift QSE-to-QSE Energy Sale per Market Participant*—The monthly sum of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTQQEP *mp, p, i* | MW | *QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| URTQQEP *mp* | MWh | *Uplift QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| DAES *mp, p, h* | MW | *Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*’s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE. |
| UDAES *mp* | MWh | *Uplift Day-Ahead Energy Sale per Market Participant*—The monthly total of energy represented by Market Participant *mp*’s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| DAEP *mp, p, h* | MW | *Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*’s cleared DAM Energy Bids at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE. |
| UDAEP *mp* | MWh | *Uplift Day-Ahead Energy Purchase per Market Participant*—The monthly total of energy represented by Market Participant *mp*’s cleared DAM Energy Bids, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTOBL *mp, (j, k), h* | MW | *Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*’s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE. |
| URTOBL *mp* | MWh | *Uplift Real-Time Obligation per Market Participant*—The monthly total of Market Participant *mp*’s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTOBLLO *q, (j, k)* | MW | *Real-Time Obligation with Links to an Option per QSE per pair of source and sink*⎯The total MW of the QSE’s PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour. |
| URTOBLLO *q, (j, k)* | MW | *Uplift Real-Time Obligation with Links to an Option per QSE per pair of source and sink*⎯The monthly total of Market Participant *mp*’s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| DAOPT *mp, (j, k), h* | MW | *Day-Ahead Option per Market Participant per source and sink pair per hour*⎯The number of Market Participant *mp*’s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder. |
| UDAOPT *mp* | MWh | *Uplift Day-Ahead Option per Market Participant*⎯The monthly total of Market Participant *mp*’s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| DAOBL *mp, (j, k), h* | MW | *Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*’s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder. |
| UDAOBL *mp* | MWh | *Uplift Day-Ahead Obligation per Market Participant*⎯The monthly total of Market Participant *mp*’s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OPTS *mp, (j, k), a, h* | MW | *PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOPTS *mp* | MWh | *Uplift PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OBLS *mp, (j, k), a, h* | MW | *PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOBLS *mp* | MWh | *Uplift PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OPTP *mp, (j, k), a, h* | MW | *PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOPTP *mp* | MWh | *Uplift PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OBLP *mp, (j, k), a, h* | MW | *PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOBLP *mp* | MWh | *Uplift PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| UWSLTOT *mp* | MWh | *Uplift Metered Energy for Wholesale Storage Load at bus per Market Participant*⎯The monthly sum of Market Participant *mp*’s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL. |
| MEBL *mp, r, b* | MWh | *Metered Energy for Wholesale Storage Load at bus*⎯The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*. |
| |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | | [NPRR1012: Insert the variables below upon system implementation of the Real-Time Co-Optimization (RTC) project:]   |  |  |  | | --- | --- | --- | | UDAASOAWD *mp* | MWh | *Uplift Day-Ahead Ancillary Service Only Award per Market Participant—*The monthly total of Market Participant *mp’s* Ancillary Service Only Offers awarded in DAM, where the Market Participant is a QSE assigned to the registered Counter-Party. | | DARUOAWD *mp, h* | MW | *Day-Ahead Reg-Up Only Award per Market Participant*⎯ The Reg-Up Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DARDOAWD *mp, h* | MW | *Day-Ahead Reg-Down Only Award per Market Participant*⎯ The Reg-Down Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DARROAWD *mp, h* | MW | *Day-Ahead Responsive Reserve Only Award per Market Participant*⎯ The RRS Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DANSOAWD *mp, h* | MW | *Day-Ahead Non-Spin Only Award per Market Participant*⎯ The Non-Spin Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DAECROAWD *mp, h* | MW | *Day-Ahead ERCOT Contingency Reserve Service Only Award per Market Participant*⎯ The ECRS Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | | | |
| |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | | ***[NPRR917: Insert the variables “*** ***USOGTOT mp”, “*** ***USOCLTOT mp”, “*** ***RTMGSOGZ mp. p, i”, “OFSOG mp, gsc, b”, “WSOL mp, gsc, b” and “NWSOL mp, gsc, b” below upon system implementation:]***   |  |  |  | | --- | --- | --- | | USOGTOT *mp* | MWh | *Uplift Real- Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by SODGs, SOTGs, SODESSs, or SOTESSs represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. | | USOCLTOT *mp* | MWh | *Uplift Real-Time Settlement Only Charging Load per Market Participant*—The monthly sum of Real-Time charging Load by Settlement Only Distribution Energy Storage Systems (SODESSs) and Settlement Only Transmission Energy Storage Systems (SOTESSs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. | | RTMGSOGZ *mp. p, i* | MWh | *Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*— The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that opted out of nodal pricing pursuant to Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), SODESS, or SOTESS, will also be included in this value. | | OFSOG *mp, gsc, b* | MWh | *Outflow as measured for an SODG, SOTG, SODESS, or SOTESS Site* ⎯The outflow as measured by the Settlement Meter(s) at Electrical Bus *b* for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by the Market Participant *mp* for the 15-minute Settlement Interval.. | | WSOL *mp, gsc, b* | MWh | *WSL for an SODESS or SOTESS Site -* The WSL as measured for an for SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by the Market Participant *mp,* represented as a negative value, for the 15-minute Settlement Interval. | | NWSOL *mp, gsc, b* | MWh | *Non-WSL Settlement Only Charging Load for an SODESS or SOTESS Site -* The Non-WSL Settlement Only Charging Load as measured for an SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by the Market Participant *mp,* represented as a negative value, for the 15-minute Settlement Interval. | | | | |
| *cp* | none | A registered Counter-Party. |
| *mp* | none | A Market Participant that is a non-defaulting QSE or CRR Account Holder. |
| *j* | none | A source Settlement Point. |
| *k* | none | A sink Settlement Point. |
| *a* | none | A CRR Auction. |
| *p* | none | A Settlement Point. |
| *i* | none | A 15-minute Settlement Interval. |
| *h* | none | The hour that includes the Settlement Interval i. |
| *r* | none | A Resource. |
| |  |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | --- | | ***[NPRR917: Insert the variables “gsc” and “b” below upon system implementation:]***   |  |  |  | | --- | --- | --- | | *gsc* | none | A generation site code. | | *b* | none | An Electrical Bus. | | | | |

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

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

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

(6) Each Default Uplift Invoice must contain:

(a) The Invoice Recipient’s name;

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

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

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

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

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

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

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

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

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

**10.1 Overview**

(1) This Section specifies the responsibilities and requirements for meter data, certification of Metering Facilities, meter standards, approved meter types and the process for auditing, testing, and maintenance of Metering Facilities to be used in the ERCOT Region.

(2) Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) are the only Entities authorized to provide Settlement Meter data to ERCOT. ERCOT shall maintain a Meter Data Acquisition System (MDAS) to collect generation and consumption energy data for Settlement purposes under these Protocols. The MDAS must receive Customer Load meter data from TSPs and DSPs and must collect data from all ERCOT-Polled Settlement (EPS) Meters.

(3) All Service Delivery Points, excluding EPS, Settlement Only Distribution Generator (SODG), Settlement Only Distribution Energy Storage System (SODESS), or Non-Opt-In Entity (NOIE) metering points, that meet the requirements of P.U.C. Subst. R. 25.311, Competitive Metering Services, are eligible for competitive meter ownership pursuant to such Public Utility Commission of Texas (PUCT) Substantive Rule. All competitively owned meters shall meet all the applicable metering requirements of these Protocols and the Retail Market Guide Section 10, Competitive Metering.

***10.2.2 TSP and DSP Metered Entities***

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

(a) All Loads using the ERCOT System;

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

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

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

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

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

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

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

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

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

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

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

***10.2.3 ERCOT-Polled Settlement Meters***

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

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

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

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

(d) Generation participating in any Ancillary Service market;

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

(f) Direct Current Ties (DC Ties);

(g) Metering required to determine the WSL or Non-WSL Settlement Only Charging Load associated to a SODESS or SOTESS; and

(h) WSL associated to a generation site.

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| ***[NPRR1002 and NPRR1020: Replace applicable portions of item (h) above with the following upon system implementation of NPRR1002; or upon implementation of NPRR1020 and upon implementation of necessary revisions to the SMOG, respectively:]***  (h) Metering required to determine WSL associated with an Energy Storage Resource (ESR). |

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| ***[NPRR1043: Insert item (i) below upon system implementation of NPRR986:]***  (i) Metering required to determine the Non-WSL ESR Charging Load. |

(2) Additionally, ERCOT shall poll any SODG or NOIE metering point at the request of such Entity, provided the Metering Facility meets all requirements and approvals associated with EPS metering requirements of this Section and the SMOG. Load Resources of 10 MW or more on the ERCOT System, may, at their option have an EPS Meter.

**10.2.3.1 Entity EPS Responsibilities**

(1) The following defines the responsibilities of Entities regarding EPS metering:

(a) EPS Meters must be polled directly by ERCOT, which shall then convert the raw data to Settlement Quality Meter Data in accordance with this Section, Section 11, Data Acquisition and Aggregation, and the SMOG.

(b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP “EPS Meter Inspector,” which is defined as an employee or agent of the TSP or DSP who has received EPS training from ERCOT, and is described further herein.

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| ***[NPRR1020: Replace paragraph (b) above with the following upon system implementation*** ***and upon implementation of necessary revisions to the SMOG:]***  (b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP “EPS Meter Inspector,” which is defined as an employee or agent of the TSP or DSP who has received EPS training from ERCOT, and is described further herein. This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter ESR, SODESS, or SOTESS auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values. |

(c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG.

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| ***[NPRR1020: Replace paragraph (c) above with the following upon system implementation*** ***and upon implementation of necessary revisions to the SMOG:]***  (c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG, except for Resource Entity-owned equipment used to measure, calculate, or telemeter an auxiliary Load value for an ESR, SODESS, or SOTESS pursuant to Section 10.2.4. |

(d) Each TSP and DSP shall install and maintain a Back-up Meter(s) at each EPS Meter location for Resources, auxiliary netting, and bi-directional meter points. A “Back-up Meter” is defined as a redundant revenue quality EPS Meter connected at the same metering point as the primary EPS Meter and meeting the requirements defined in the SMOG.

(e) Costs incurred in the installation and maintenance of EPS metered Facilities and communications will be the responsibility of the TSP or DSP except for incremental costs incurred for functions not required for the energy settlement as required by these Protocols. These incremental costs shall be borne by the Entities requesting the service, as per the TSP’s or DSP’s tariffs.

(f) Specific operating practices for EPS Metering Facilities are included in the SMOG.

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| ***[NPRR1020: Insert Section 10.2.4 below upon system implementation*** ***and upon implementation of necessary revisions to the SMOG:]***  ***10.2.4 Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values***  (1) When the Resource Entity certifies, the interconnecting TDSP confirms by approving the metering design, and, based on the information provided by the TDSP as part of the EPS Design Proposal, ERCOT agrees that metering of an ESR’s WSL separate from the ESR’s, SODESS’s, or SOTESS’s auxiliary Load is not feasible based on the ESR’s, SODESS’s, or SOTESS’s physical design, the Resource Entity for that ESR, SODESS, or SOTESS shall be permitted to calculate the auxiliary Load using measurements from its own internal sensors and telemeter a Real-Time aggregated value for that Load to the TDSP’s EPS Meter. The Resource Entity may telemeter a zero Load value only when the ESR, SODESS, or SOTESS is discharging more than the calculated auxiliary Load. The methodology by which the auxiliary Load is calculated is subject to ERCOT approval.  (2) An officer of the Resource Entity shall annually attest to the methodology and validity of the auxiliary Load calculation, as further described in the SMOG. The Resource Entity shall include with its annual attestation the findings of an independent audit performed by a registered Texas Professional Engineer confirming the auxiliary Load calculation does not understate the Load value. The audit shall be based on laboratory testing that reflects the anticipated field conditions of the same model of sensor as that used by the Resource Entity or validation using measurements by other devices over the past year, as further described in the SMOG. The audit shall evaluate the impact of any degradation in accuracy of the sensors over time.  (3) If the Resource Entity is unable to provide the attestation and audit findings meeting the requirements of paragraph (2) above, it shall either reconfigure the Resource Entity’s site and resubmit its meter design within 30 days to allow for separately metering the WSL or forfeit WSL treatment.  (4) ERCOT may conduct an audit of the Resource Entity’s processes, equipment, and calculation of the auxiliary Load.  (5) The TSP or DSP shall assign all costs required for separately metering the auxiliary Load for WSL treatment to the EPS Meter to the Resource Entity. |

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| ***[NPRR1020: Insert Section 10.2.4.1 below upon system implementation*** ***and upon implementation of necessary revisions to the SMOG:]***  **10.2.4.1 Responsibilities for Resource Entity Calculation and Telemetry of ESR, SODESS, or SOTESS Auxiliary Load Values**  (1) For each site at which a Resource Entity telemeters its auxiliary Load value, as permitted by Section 10.2.4:  (a) The Resource Entity shall:  (i) Provide supporting information on the equipment, configuration, drawings and processes used to calculate the telemetry signal, including supporting information on the calculation of the telemetry signal for inclusion in the EPS Design Proposal.  (ii) Provide documentation of the auxiliary Load calculation methodology as defined in this Section and the SMOG.  (iii) Install, control, and maintain the sensors, instrumentation, wiring, communications, and other equipment required to calculate and provide the telemetry signal.  (iv) Provide and update contact information for a person designated for communication regarding the auxiliary Load supporting information and data.  (v) Act in accordance with any TDSP requirements concerning EPS Meters and Metering Facilities in the Protocols and SMOG that pertain to the following issues:   1. calculation of Load values and data estimation issues; 2. the provision of notice to ERCOT regarding any outage or any other issue affecting the accuracy of the Load calculation or the availability of the telemetry of the Load value; and 3. the implementation of any proposed change to the calculation or equipment, as documented in the EPS Design Proposal; and   (vi) Provide any information requested by ERCOT or the TDSP with respect to the measurement, calculation, and/or telemetry of the auxiliary Load value.  (b) The interconnecting TDSP shall:  (i) Use an EPS Meter to calculate 15 minute energy values from the Resource Real-Time telemetry signal for the auxiliary Load and store the data in the EPS Meter for retrieval by the ERCOT Meter Data Acquisition System (MDAS); and  (ii) Include an auxiliary Load metering point on the EPS Design Proposal that represents the calculation of the telemetry signal.  (c) ERCOT shall:  (i) Review the Resource-provided data on the calculation of the telemetry signal submitted as part of the EPS Design Proposal to ensure compliance with defined rules in this Section and the SMOG; and  (ii) Request assistance and information from the Resource-designated contact for items related to the telemetry. |

**10.3.2.3 Generation Netting for ERCOT-Polled Settlement Meters**

(1) 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 POIs to the ERCOT Transmission Grid. Interval Data Recorders (IDRs) must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load and carry any applicable Load shared charges and credits.

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| ***[NPRR917: Replace paragraph (1) above with the following upon system implementation:]***  (1) At Generation Resource and Settlement Only Generator (SOG) Facilities, generation and associated Loads, including construction and maintenance Load that is netted with existing generation auxiliaries, must be metered at their POIs to the ERCOT Transmission Grid or Service Delivery Point. Interval Data Recorders (IDRs) must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load and carry any applicable Load shared charges and credits. |

(2) For Settlement purposes, generation netting is not allowed except under one of the following conditions:

(a) Single POI with delivered and received metering data channels;

(b) Multiple POIs where the Loads and generator output are electrically connected to a common switchyard, as defined in paragraph (6) below. In addition, there must be sufficient generator capacity to serve all plant Loads for netting to occur;

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

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

(e) A QF that meets the requirements for a small power production facility under 18 C.F.R. § 292.204 and will lawfully provide energy to a Customer behind a single POI with delivered and received metering data channels.

(3) For generation sites with EPS Meters that measure Wholesale Storage Load (WSL), each energy storage Load Resource must be separately metered from all other Loads and generation:

(a) For configurations where the WSL is not at the POI, it must be separately metered behind a single POI metering point; and

(b) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (6) below.

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| ***[NPRR1020: Replace paragraph (3) above with the following upon system implementation*** ***and upon implementation of necessary revisions to the SMOG:]***  (3) For Energy Storage Resource (ESR), SODESS, or SOTESS sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.  (a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:  (i) The total energy into the ESR, SODESS, or SOTESS must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities and  (ii) The auxiliary Load energy shall be stored in the EPS Meter’s IDR, per channel assignments defined in the SMOG.  (b) For configurations where the WSL is not at the POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and  (c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (6) below. |

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

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

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

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| ***[NPRR945: Insert paragraph (7) below upon system implementation:]***  (7) ERCOT shall post on the ERCOT website a report listing all Generation Resources or Settlement Only Generators (SOGs) that have achieved commercial operations, excluding Decommissioned Generation Resources, Mothballed Generation Resources, and decommissioned SOGs, whose Resource Registration data indicates that the Generation Resource or SOG is part of a Private Use Network. The report must identify the name of the Generation Resource or SOG site, its nameplate capacity, and the date the Generation Resource or SOG was added to the report. The report shall not identify any confidential, customer-specific information regarding netted loads. ERCOT shall update the list at least monthly. |

***10.9.1 ERCOT-Polled Settlement Meters***

(1) The TSP or DSP for ERCOT-Polled Settlement (EPS) Meters shall ensure that the EPS Metering Facilities comply with this Section and the Settlement Metering Operating Guide (SMOG).

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| ***[NPRR1020: Replace paragraph (1) above with the following upon system implementation*** ***and upon implementation of necessary revisions to the SMOG:]***  (1) The TSP or DSP for ERCOT-Polled Settlement (EPS) Meters shall ensure that the EPS Metering Facilities comply with this Section and the Settlement Metering Operating Guide (SMOG). This requirement does not apply to Resource Entity-owned Metering Facilities used to measure, calculate, or telemeter Energy Storage Resource (ESR), SODESS, or SOTESS auxiliary Load pursuant to Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values. |

(2) IDRs used for settlement of EPS Metering Facilities shall:

(a) Capture energy consumption and/or production in increments consistent with ERCOT defined Settlement Interval;

(b) Be able to capture energy in increments of five minutes (excluding memory allocation) for new and replacement IDRs used for settlement;

(c) Provide interval data for daily polling on a schedule that supports ERCOT’s requirements (typically a daily cycle);

(d) Be capable of having data retrieved via telemetry by Meter Data Acquisition System (MDAS);

(e) Have battery or other energy-storage back-up to maintain time during power outages;

(f) Have remote time synchronization capability compatible with the MDAS;

(g) Maintain meter clocks on a time reference standard that enables ERCOT MDAS to maintain the IDR data on Central Prevailing Time (CPT). The meter clock shall be synchronized to within +/- 1% of the Settlement Interval when compared with the National Institute of Standards and Technology (NIST) Atomic Clock. ERCOT shall perform the time synchronization for meters at the time of the interrogation if the meter is outside tolerance; and,

(h) Divide each hour into Settlement Intervals ending as follows:

XX:15:00

XX:30:00

XX:45:00

XX:00:00

***11.1.6 ERCOT Polled Settlement Meter Netting***

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

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| ***[NPRR1002: Replace paragraph (1) above with the following upon system implementation:]***  (1) As allowed by Section 10, Metering, of these Protocols, ERCOT will perform the approved netting schemes, which sum the meters at a given Generation Resource, or Energy Storage Resource (ESR) site. |

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

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| ***[NPRR1002: Replace paragraph (2) above with the following upon system implementation:]***  (2) Both Load consumption and generation production meters will be combined together to obtain a total amount of Load or generation. |

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

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| ***[NPRR1002: Replace paragraph (3) above with the following upon system implementation:]***  (3) For an ESR site: |

(a) WSL is measured by the corresponding EPS Meter.

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| ***[NPRR1020: Replace paragraph (a) above with the following upon system implementation and upon*** ***implementation of necessary revisions to the Settlement Metering Operating Guide (SMOG):]***  (a) WSL is measured by the corresponding EPS Meter, except that when a Resource Entity for an Energy Storage Resource (ESR) communicates its auxiliary Load value to the EPS Meter, WSL is calculated by subtracting the auxiliary Load from the total Load measured by the corresponding EPS meter. If the calculated auxiliary Load is greater than the total Load, WSL shall be zero. |

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

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

(4) For an SODESS or SOTESS that has been approved for WSL treatment and has a single POI or Service Delivery Point:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**16.5 Registration of a Resource Entity**

(1) A Resource Entity owns or controls a Generation Resource, Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT’s reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Generation Resource, SOG, SOESS, or Load Resource through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion.

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| ***[NPRR1002: Replace paragraph (1) above with the following upon system implementation:]***  (1) A Resource Entity owns or controls a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT’s reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource, SOG, or SOESS through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. |

(2) Prior to commissioning, Resources Entities will regularly update the data necessary for modeling. These updates will reflect the best available information at the time submitted.

(3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, SOG, or SOESS meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, SOG, or SOESS in Exhibit “C” (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2 to assess whether the Generation Resource, SOG, or SOESS, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, SOG, or SOESS within 90 days of the date the Generation Resource, SOG, or SOESS meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, SOG, or SOESS violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

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| ***[NPRR1002: Replace paragraph (3) above with the following upon system implementation:]***  (3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, ESR, SOG, or SOESS meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, ESR, SOG, or SOESS in Exhibit “C” (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2, to assess whether the Generation Resource, ESR, SOG, or SOESS, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, ESR, SOG, or SOESS within 90 days of the date the Generation Resource, ESR, SOG, or SOESS meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, ESR, SOG, or SOESS violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination. |

(4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:

(a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT’s satisfaction that the Generation Resource, SOTG, SOTSG, or SOTESS can comply with these standards;

(b) The requirements of Planning Guide Section 5.9, Quarterly Stability Assessment, have not been completed for the Generation Resource, SOTG, SOTSG, or SOTESS; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

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| ***[NPRR1002 and NPRR1016: Replace applicable portions of paragraph (4) above with the following upon system implementation:]***  (4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG),Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:  (a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT’s satisfaction that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS can comply with these standards;  (b) The requirements of Planning Guide Section 5.9, Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, SOTSG, or SOTESS; or  (c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT. |

(5) DG with an installed capacity greater than one MW, the DG registration threshold, which exports energy into a Distribution System, must register with ERCOT.

(6) A Resource Entity representing an Energy Storage Resource (ESR) shall register the ESR as both a Generation Resource and a Controllable Load Resource.

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| ***[NPRR1002: Replace paragraph (6) above with the following upon system implementation:]***  (6) A Resource Entity representing an ESR shall register the ESR as an ESR. ERCOT systems, including the Energy and Market Management System (EMMS) and Settlement system, shall continue to treat the ESR as both a Generation Resource and a Controllable Load Resource until such time as all ERCOT systems are capable of treating an ESR as a single Resource. |

**16.5.1.2 Waiver for Federal Hydroelectric Facilities**

(1) ERCOT may grant a waiver to any federally owned hydroelectric Generation Resource, SOG, SOESS, or Load Resource within the ERCOT System from fulfilling the requirements in Section 16.5, Registration of a Resource Entity, as they pertain to the submission of a Resource Entity application and the execution of a Market Participant Agreement (Section 22, Attachment A, Standard Form Market Participant Agreement). ERCOT may grant such waiver after the federally owned hydroelectric Resource Entity provides ERCOT with the following:

(a) All information necessary to meet the Resource Entity registration requirements as provided in this Section;

(b) The designation of a QSE for each Generation Resource, SOG, SOESS, or Load Resource that it owns or controls; and

(c) Assignment of each Generation Resource’s, SOG’s, SOESS’s, or Load Resource’s Electric Service Identifier (ESI ID) to a Load Serving Entity (LSE) serving any Load or net Load, if the Generation Resource, SOG, SOESS, or Load Resource is net metered and will be connected to the ERCOT System. Such Load, if retail Load, is subject to all applicable rules and procedures, including rules concerning disconnection and Provider of Last Resort (POLR) service, applicable to other retail points of delivery.

***16.11.4.3.2 Real-Time Liability Estimate***

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

(a) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node, using Real-Time Metered Generation (RTMG) as generation estimate;

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

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| ***[NPRR829: Replace item (b) above with the following upon system implementation:]***  (b) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone, using 14 day or seven day old LRS for Load estimate and Real-Time telemetry of net generation as the generation estimate; |

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

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

(e) Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;

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| ***[NPRR917: Insert item (f) below upon system implementation and renumber accordingly:]***  (f) Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS), using the Real-Time telemetry, if provided, of net generation as the outflow estimate and the Real-Time Price for each SODG, SOTG, SODESS, or SOTESS site; |

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

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| [NPRR1013: Insert items (g)-(k) below upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]  (g) Section 6.7.5.1, Regulation Up Payments and Charges;  (h) Section 6.7.5.2, Regulation Down Payments and Charges;  (i) Section 6.7.5.3, Responsive Reserve Payments and Charges;  (j) Section 6.7.5.4, Non-Spinning Reserve Payments and Charges; and  (k) Section 6.7.5.5, ERCOT Contingency Reserve Service Payments and Charges. |

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

**ERCOT Nodal Protocols**

**Section 22**

**Attachment L: Declaration of Private Use Network Net Generation Capacity Availability**

**November 1, 2019**

**Declaration of Private Use Network Net Generation Capacity Availability**

A Private Use Network is an electric network connected to the ERCOT Transmission Grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation). A Resource Entity that represents a Generation Resource, a Settlement Only Generator (SOG), or a Settlement Only Energy Storage System (SOESS) in a Private Use Network shall use this form to provide ERCOT with information required by ERCOT Protocol Section 10.3.2.4, Reporting of Net Generation Capacity. This form must be submitted to ERCOT by February 1 of each year. ERCOT shall treat this information as Protected Information in accordance with paragraph (1)(x) of Section 1.3.1.1, Items Considered Protected Information.

Please fill out this form electronically, print and sign. The form can be sent to ERCOT via email to [MPRegistration@ercot.com](mailto:MPRegistration@ercot.com) (.pdf), via facsimile to (512) 225-7079, or via mail to ERCOT, Attention: Market Participant Registration, 7620 Metro Center Drive, Austin, Texas 78744.

Date of Notice:

|  |  |
| --- | --- |
| Resource Entity: | DUNS Number: |

Facility Name:

In the table below, enter the incremental forecasted changes in net generation capacity (in Megawatts) available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and year-on-year changes as of May 31 for the next 10 subsequent years. The capacity forecasts should account for changes in both process loads and self-generation capability. Example: If the capacity change is -75 MW from May 31 of the previous calendar year to May 31 of the current year, enter -75 MW in line 1. If the capacity change is 100 MW from May 31 of the current calendar year to May 31 of the next calendar year, enter 100 MW in line 2. DO NOT enter cumulative annual changes. (For this example, do not enter 25 MW in line 2).

| **Line#** | **Annual Forecast Periods** | **Expected Change in Net Generation Capacity Available to the ERCOT Grid, MW** |
| --- | --- | --- |
| 1 | May 31 of previous calendar year to May 31 of current calendar year |  |
| 2 | May 31 of current calendar year to May 31 of forecast year 1 |  |
| 3 | May 31 of forecast year 1 to May 31 of forecast year 2 |  |
| 4 | May 31 of forecast year 2 to May 31 of forecast year 3 |  |
| 5 | May 31 of forecast year 3 to May 31 of forecast year 4 |  |
| 6 | May 31 of forecast year 4 to May 31 of forecast year 5 |  |
| 7 | May 31 of forecast year 5 to May 31 of forecast year 6 |  |
| 8 | May 31 of forecast year 6 to May 31 of forecast year 7 |  |
| 9 | May 31 of forecast year 7 to May 31 of forecast year 8 |  |
| 10 | May 31 of forecast year 8 to May 31 of forecast year 9 |  |
| 11 | May 31 of forecast year 9 to May 31 of forecast year 10 |  |

Describe any future load expansions, equipment shutdowns, or new self-generation associated with the capacity changes reported above.

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By signing below, I certify that I am authorized to execute and submit this Notice on behalf of the above Resource Entity, and that the data and statements contained herein are true and correct to the best of my knowledge.

Signature of Authorized Signatory:

Name: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Title: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Phone: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

**ERCOT Nodal Protocols**

**Section 23**

**Form I: Resource Entity Application for Registration**

**March 13, 2020**

**RESOURCE ENTITY**

**APPLICATION FOR REGISTRATION**

This application is for approval as a Resource Entity by the Electric Reliability Council of Texas Inc. (ERCOT) in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary. The completed, executed application will be accepted by ERCOT via email to [MPRegistration@ercot.com](mailto:MPRegistration@ercot.com) (.pdf version), via facsimile to (512) 225-7079, or via mail to Market Participant Registration, 7620 Metro Center Drive, Austin, Texas 78744. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

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

**PART I – ENTITY Information**

|  |  |
| --- | --- |
| **Legal Name of the Applicant:** |  |
| **Legal Address of the Applicant:** | Street Address: |
|  | City, State, Zip: |
| **DUNS¹ Number:** |  |

¹Defined in Section 2.1, Definitions.

**1. Authorized Representative (“AR”).** Defined in Section 2.1, Definitions.

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name:** | | |  | | | | **Title:** |  | | |
| **Address:** | |  | | | | | | | | |
| **City:** |  | | | | **State:** |  | | | **Zip:** |  |
| **Telephone:** | |  | | | | **Fax:** |  | | | |
| **Email Address:** | | | |  | | | | | | |

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

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name:** | | |  | | | | **Title:** |  | | |
| **Address:** | |  | | | | | | | | |
| **City:** |  | | | | **State:** |  | | | **Zip:** |  |
| **Telephone:** | |  | | | | **Fax:** |  | | | |
| **Email Address:** | | | |  | | | | | | |

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

Individual  Partnership  Municipally Owned Utility

Electric Cooperative  Limited Liability Company  Corporation

Other:

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

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

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| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name:** | | |  | | | | **Title:** |  | | |
| **Address:** | |  | | | | | | | | |
| **City:** |  | | | | **State:** |  | | | **Zip:** |  |
| **Telephone:** | |  | | | | **Fax:** |  | | | |
| **Email Address:** | | | |  | | | | | | |

**5. Backup USA.** *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

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| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name:** | | |  | | | | **Title:** |  | | |
| **Address:** | |  | | | | | | | | |
| **City:** |  | | | | **State:** |  | | | **Zip:** |  |
| **Telephone:** | |  | | | | **Fax:** |  | | | |
| **Email Address:** | | | |  | | | | | | |

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

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name:** | | |  | | | | **Title:** |  | | |
| **Address:** | |  | | | | | | | | |
| **City:** |  | | | | **State:** |  | | | **Zip:** |  |
| **Telephone:** | |  | | | | **Fax:** |  | | | |
| **Email Address:** | | | |  | | | | | | |

**7. Compliance Contact.** This person is responsible for compliance related issues.

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name:** | | |  | | | | **Title:** |  | | |
| **Address:** | |  | | | | | | | | |
| **City:** |  | | | | **State:** |  | | | **Zip:** |  |
| **Telephone:** | |  | | | | **Fax:** |  | | | |
| **Email Address:** | | | |  | | | | | | |

**8. Proposed commencement date for service:**      .

**PART II – ADDiTIONAL REQUIRED Information**

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

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

**3. Qualified Scheduling Entity (QSE) Acknowledgment.** Provide all information requested in Attachment A and have the document executed by both parties. Resource Entities representing Generation Resources or Load Resources shall designate a QSE qualified to represent the Resources. Resource Entities with Settlement Only Generators (SOGs) or Settlement Only Energy Storage Systems (SOESSs) shall designate any qualified QSE.

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

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

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

**Attachment A – QSE Acknowledgment**

**Acknowledgment by Designated QSE for**

**Scheduling and Settlement Responsibilities with ERCOT**

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

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

The requested effective date for such representation is:      [[1]](#footnote-1)\*\*

or

Establish partnership at the earliest possible date

Acknowledgment by **QSE**:

|  |  |
| --- | --- |
| Signature of Authorized Representative (“AR”) for QSE: |  |
| Printed Name of AR: |  |
| Email Address of AR: |  |
| Date: |  |
| Name of Designated QSE: |  |
| DUNS of Designated QSE: |  |

Acknowledgment by **Applicant**:

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

1. \*\* *Actual effective date will depend on time needed to implement the relationship in ERCOT systems once ERCOT has received all necessary information (a minimum of three Business Days), and may be later than the requested effective date. ERCOT will notify the parties of the actual effective date*. [↑](#footnote-ref-1)