|  |  |  |  |
| --- | --- | --- | --- |
| NPRR Number | [1246](https://www.ercot.com/mktrules/issues/NPRR1246) | NPRR Title | Energy Storage Resource Terminology Alignment for the Single-Model Era |
| Date of Decision | | December 3, 2024 | |
| Action | | Remanded | |
| Timeline | | Normal | |
| Estimated Impacts | | Cost/Budgetary: None  Project Duration: Not applicable | |
| Proposed Effective Date | | Upon system implementation of PR447, Real-Time Co-Optimization (RTC) | |
| Priority and Rank Assigned | | Not applicable | |
| Nodal Protocol Sections Requiring Revision | | 1.3.1.1, Items Considered Protected Information  1.3.1.2, Items Not Considered Protected Information  1.6.5, Interconnection of New or Existing Generation  2.1, Definitions  2.2, Acronyms and Abbreviations  3.1.1, Role of ERCOT  3.1.3.2, Resources  3.1.4.5, Notice of Forced Outage or Unavoidable Extension of Planned, Maintenance, or Rescheduled Outage Due to Unforeseen Events  3.1.5.1, ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities  3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests  3.6.1, Load Resource Participation  3.8.5, Energy Storage Resources  3.10.1, Time Line for Network Operations Model Changes  3.10.3, CRR Network Model  3.10.6, Resource Entity Responsibilities  3.10.7.1.4. Transmission and Generation Resource Step-Up Transformers  3.10.7.2, Modeling of Resources and Transmission Loads  3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits  3.10.7.7, DC Tie Limits  3.14.1.9, Generation Resource Status Updates  3.14.4.1, Overview and Description of MRAs  3.14.4.5, Standards for Generation Resource MRAs  3.14.4.7, MRA Testing  3.17.1, Regulation Service  3.17.2, Responsive Reserve Service  3.17.3, Non-Spinning Reserve Service  3.17.4, ERCOT Contingency Reserve Service  3.18, Resource Limits in Providing Ancillary Service  3.22.1.2, Generation Resource Interconnection Assessment  3.22.1.3, Transmission Project Assessment  3.22.1.4, Annual SSR Review  3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria  3.22.3, Subsynchronous Resonance Monitoring  4.4.6.3, PTP Obligations with Links to an Open DAM Award Eligibility  4.4.7.1, Self-Arranged Ancillary Service Quantities  4.4.7.3, Ancillary Service Trades  4.4.9.3.3, Energy Offer Curve Cost Caps  6.5.1.1, ERCOT Control Area Authority  6.5.3, Equipment Operating Ratings and Limits  6.5.5.1, Changes in Resource Status  6.5.7.1.13, Data Inputs and Outputs for the Real-Time Sequence and SCED  6.5.7.4, Base Points  6.5.7.4.1, Updated Desired Set Points  6.5.7.6.2.2, Deployment of Responsive Reserve (RRS)  6.5.7.6.2.3, Non-Spinning Reserve Service Deployment  6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service  6.5.7.8, Dispatch Procedures  6.5.8, Verbal Dispatch Instruction Confirmation  6.5.9.4, Energy Emergency Alert  6.5.9.4.2, EEA Levels  6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment  6.6.5.2, Set Point Deviation Charge for Over Generation  6.6.5.2.1, Set Point Deviation Charge for Under Generation  6.6.5.4, Set Point Deviation Payment  6.6.7.1, Voltage Support Service Payments  6.6.9, Emergency Operations Settlement  8.1, QSE and Resource Performance Monitoring  8.1.1.1, Ancillary Service Qualification and Testing  8.1.1.2.1.7, ERCOT Contingency Reserve Service Qualification  8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics  8.2, ERCOT Performance Monitoring  8.4, ERCOT Response to Market Non-Performance  9.17.1, Billing Determinant Data Elements  9.19.1, Default Uplift Invoices  10.2.2, TSP and DSP Metered Entities  10.3.2.1.6, Allocating EPS Metered Data to Generator Owners When It Is Net Load  10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters  10.3.2.4, Reporting of Net Generation Capacity  11.5.2, Generation Meter Data Aggregation  11.5.2.1, Participant Specific Generation Data Posting/Availability  13.2.4, Seasonal Transmission Loss Factor Calculation  16.5, Registration of a Resource Entity  16.14, Termination of Access Privileges to Restricted Computer Systems and Control Systems  26.2, Securitization Default Charges  Section 22, Attachment E, Notification of Suspension of Operations  Section 22, Attachment H, Notification of Generation Resource Designation  Section 22, Attachment L, Declaration of Private Use Network Net Generation Capacity Availability  Section 22, Attachment N, Standard Form Must-Run Alternative Agreement  Section 22, Attachment P, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints  Section 23, Form I, Resource Entity Application for Registration | |
| Related Documents Requiring Revision/Related Revision Requests | | Nodal Operating Guide Revision Request (NOGRR) 268, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era  Other Binding Document Revision Request (OBDRR) 052, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era  Planning Guide Revision Request (PGRR) 118, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era | |
| Revision Description | | This Nodal Protocol Revision Request (NPRR) inserts terminology associated with Energy Storage Resources (ESRs) in the appropriate places throughout the Protocols, aligning provisions and requirements for ESRs with those already in place for Generation Resources and Controllable Load Resources.  NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions, which was approved by the ERCOT Board of Directors at its August 11, 2020, meeting, included a blanket provision in paragraph (1) of Section 3.8.5, Energy Storage Resources, as follows:  “For the purposes of all ERCOT Protocols and Other Binding Documents, all requirements that apply to Generation Resources and Controllable Load Resources shall be understood to apply to Energy Storage Resources (ESRs) to the same extent, except where the Protocols explicitly provide otherwise.”  As discussed at meetings in 2020 of the Battery Energy Storage Task Force (BESTF), ERCOT intended for this provision to be temporary, and explained to stakeholders that it would introduce an NPRR and related Revision Requests that incorporated the ESR terminology in all appropriate locations in the Protocols. This NPRR will accomplish that objective.  This NPRR applies to ESRs in the future single-model era and should be implemented simultaneously with NPRR1014, BESTF-4 Energy Storage Resource Single Model.  ERCOT invites review of this NPRR from the Real-Time Co-Optimization plus Batteries Task Force (RTCBTF) and any other applicable groups. It is also worth noting these changes have no system impacts as they reflect the current RTC+B business requirements and interface requirements for Market Participants. | |
| Reason for Revision | | [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 1 – Be an industry leader for grid reliability and resilience  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 2 - Enhance the ERCOT region’s economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission  General system and/or process improvement(s)  Regulatory requirements  ERCOT Board/PUCT Directive  *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)* | |
| Justification of Reason for Revision and Market Impacts | | By incorporating terminology in all appropriate places in the Protocols, this NPRR provides clarity and additional transparency for stakeholders on the applicable provisions and requirements associated with ESRs. With the implementation of this NPRR at the time of RTC+B go-live, all references to the Combo-Model will be removed. | |
| PRS Decision | | On 9/12/24, PRS voted unanimously to table NPRR1246. All Market Segments participated in the vote.  On 10/17/24, PRS voted unanimously to recommend approval of NPRR1246 as amended by the 9/20/24 ERCOT comments. All Market Segments participated in the vote.  On 11/14/24, PRS voted unanimously to endorse and forward to TAC the 10/17/24 PRS Report and 7/31/24 Impact Analysis for NPRR1246. All Market Segments participated in the vote. | |
| Summary of PRS Discussion | | On 9/12/24, ERCOT Staff provided an overview of NPRR1246.  On 10/17/24, participants reviewed the 9/20/24 ERCOT comments and noted the recent ROS vote to recommend approval of the related NOGRR268 and PGRR118.  On 11/14/24, there was no discussion. | |
| TAC Decision | | On 11/20/24, TAC voted unanimously to recommend approval of NPRR1246 as recommended by PRS in the 11/14/24 PRS Report. All Market Segments participated in the vote. | |
| Summary of TAC Discussion | | On 11/20/24, there was no additional discussion beyond TAC review of the items below. | |
| TAC Review/Justification of Recommendation | | Revision Request ties to Reason for Revision as explained in Justification  Impact Analysis reviewed and impacts are justified as explained in Justification  Opinions were reviewed and discussed  Comments were reviewed and discussed (if applicable)  Other: (explain) | |
| ERCOT Board Decision | | On 12/3/24, the ERCOT Board voted unanimously to remand NPRR1246 to TAC. | |

|  |  |
| --- | --- |
| **Opinions** | |
| Credit Review | ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1246 and do not believe that it requires changes to credit monitoring activity or the calculation of liability. |
| Independent Market Monitor Opinion | IMM has no opinion on NPRR1246. |
| ERCOT Opinion | ERCOT supports approval of NPRR1246. |
| ERCOT Market Impact Statement | ERCOT Staff has reviewed NPRR1246 and believes the market impact for NPRR1246 provides clarity and additional transparency for stakeholders on the applicable provisions and requirements associated with ESRs as the market transitions from the combo model to the single model as part of the RTC+B project. |

|  |  |
| --- | --- |
| Sponsor | |
| Name | Kenneth Ragsdale / Magie Shanks |
| E-mail Address | [Kenneth.ragsdale@ercot.com](mailto:Kenneth.ragsdale@ercot.com) / [magie.shanks@ercot.com](mailto:magie.shanks@ercot.com) |
| Company | ERCOT |
| Phone Number |  |
| Cell Number | 512-750-3505 / 512-248-6472 |
| Market Segment | Not applicable |

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

|  |  |
| --- | --- |
| **Comments Received** | |
| Comment Author | **Comment Summary** |
| ROS 091024 | Requested PRS table NPRR1246 |
| ERCOT 092024 | Proposed additional clarifying edits based on stakeholder discussions |

|  |
| --- |
| Market Rules Notes |

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

* NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions (unboxed 9/27/24)
  + Section 3.8.5
  + Section 16.5
* NPRR1131, Controllable Load Resource Participation in Non-Spin (unboxed 8/23/24)
  + Section 6.5.7.6.2.3
* NPRR1058, Resource Offer Modernization (unboxed 8/23/24)
  + Section 6.6.9
* NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources (incorporated 12/1/24)
  + Section 1.3.1.1
  + Section 3.6.1
  + Section 6.5.7.4
  + Section 6.5.7.6.2.3
  + Section 8.1.1.1
  + Section 9.19.1
  + Section 10.2.2
  + Section 10.3.2.3
  + Section 26.2
* NPRR1198, Congestion Mitigation Using Topology Reconfigurations (incorporated 8/1/24)
  + Section 6.5.1.1
* NPRR1216, Implementation of Emergency Pricing Program (incorporated 10/1/24)
  + Section 4.4.9.3.3
* NPRR1217, Remove VDI Requirement for Deployment and Recall of Load Resources and ERS Resources (incorporated 10/1/24)
  + Section 6.5.9.4.2
* NPRR1218, REC Program Changes Per P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program (unboxed 11/1/24)
  + Section 1.3.1.1
* NPRR1225, Exclusion of Lubbock Load from Securitization Charges (incorporated 10/1/24)
  + Section 26.2
* NPRR1230, Methodology for Setting Transmission Shadow Price Caps for an IROL in SCED (unboxed 10/2/24)
  + Section 22, Attachment P
* NPRR1244, Related to NOGRR263, Clarification of Controllable Load Resource Primary Frequency Response Responsibilities (incorporated 12/1/24)
  + Section 3.6.1

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

* NPRR1190, High Dispatch Limit Override Provision for Increased Load Serving Entity Costs
  + Section 6.6.3.6
* NPRR1221, Related to NOGRR262, Provisions for Operator-Controlled Manual Load Shed
  + Section 6.5.9.4.2
* NPRR1226, Demand Response Monitor
  + Section 6.5.7.1.13
* NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
  + Section 3.1.1
  + Section 3.1.5.11
  + Section 3.10.7.2
  + Section 3.22.1.2
  + Section 3.22.1.3
  + Section 3.22.1.4
  + Section 3.22.2
  + Section 3.22.3
  + Section 16.5
* NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  + Section 3.18
  + Section 4.4.7.1
  + Section 4.4.7.3
* NPRR1239, Access to Market Information
  + Section 6.5.7.1.13
  + Section 8.1
* NPRR1240, Access to Transmission Planning Information
  + Section 3.1.3.2
* NPRR1254, Modeling Deadline for Initial Submission of Resource Registration Data
  + Section 3.10.1
* NPRR1255, Introduction of Mitigation of ESRs
  + Section 3.8.5
* NPRR1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response
  + Section 3.18
* NPRR1260, Corrections for CLR Requirements Inadvertently Removed
  + Section 3.17.2

|  |
| --- |
| Proposed Protocol Language Revision |

**1.3.1.1 Items Considered Protected Information**

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

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

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

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

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

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

|  |
| --- |
| ***[NPRR1013 and NPRR1188: Replace applicable portions of paragraph (b) above with the following upon system implementation for NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1013:]***  (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) The prices and quantities presented in a Resource’s Energy Offer Curve or Energy Bid Curve by Operating Hour or SCED interval. The Protected Information status of this information shall expire within seven days after the applicable Operating Day if required to be posted as part of paragraph (5) of Section 3.2.5 and within two days after the applicable Operating Day if required to be posted as part of paragraph (7) of Section 3.2.5; |

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

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

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

(B) The Resource’s fuel type;

(C) The type of Outage or derate;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(p) Credit limits identifiable to a specific QSE;

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

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

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

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

|  |
| --- |
| ***[NPRR857: Replace item (t) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (t) QSE, Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), and Distribution Service Provider (DSP) backup plans collected by ERCOT under the Protocols or Other Binding Documents; |

(u) Direct Current Tie (DC Tie) Schedule information. The Protected Information status of this information shall expire on the date on which ERCOT files the report with the PUCT that is required by P.U.C. Subst. R. 25.192, Transmission Rates for Export from ERCOT, relating to energy imported and exported over DC Ties interconnected to the ERCOT System;

(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 the probability of return to service and expected lead time for returning to service for a Mothballed Generation Resource or Mothballed Energy Storage Resource (ESR), submitted pursuant to Section 3.14.1.9, Generation Resource/Energy Storage 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 submitted notice to have their Load excluded from the Solar Renewable Portfolio Standard (SRPS) calculation consistent with Section 14.5.3, End-Use Customers, and subsection (f) of P.U.C. Subst. R. 25.173, Renewable Energy Credit Program, or the Renewable Portfolio Standard (RPS) calculation consistent with subsection (j) of P.U.C. Subst. R. 25.173 as it was effective until December 31, 2023;

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

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

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

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

|  |
| --- |
| ***[NPRR829 and NPRR995: Replace applicable portions of paragraph (ee) above with the following upon system implementation:]***  (ee) Status of Settlement Only Generators (SOGs) and Settlement Only Energy Storage System (SOESS), including Outages, limitations, schedules, metered output and withdrawal data, or data telemetered for use in the calculation of Real-Time Liability (RTL) as described in Section 16.11.4.3.2, Real-Time Liability Estimate, except that ERCOT may disclose metered output and withdrawal data from an SOG or SOESS as part of an extract or forwarded TX SET transaction provided to the LSE associated with the ESI ID of the Premise where the SOG is located. The Protected Information status of this information shall expire 60 days after the applicable Operating Day; |

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

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

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

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

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

(kk) Information provided to ERCOT:

(i) By a QSE under paragraph (3) of Section 3.14.5, Firm Fuel Supply Service, as part of an offer to provide Firm Fuel Supply Service (FFSS), except that within ten Business Days of issuing FFSS awards, ERCOT may disclose the identity of all Generation Resources that were offered as primary Generation Resources or alternate Generation Resources to provide FFSS for the most recent procurement period, including prices and quantities offered;

(ii) By a Resource Entity under paragraph (2) of Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, and Decertification, as part of the voluntary process for ERCOT certification of a FFSS Qualified Contract; or

(iii) By a Resource Entity in a Force Majeure Event report required under paragraph (14) of Section 8.1.1.2.6;

(ll) Information provided to ERCOT pursuant to Section 16.2.1.1, QSE Background Check Process, or Section 16.8.1.1, CRR Account Holder Background Check Process; and

(mm) Information concerning coal or lignite inventory provided by a QSE under Section 3.24, Notification of Low Coal and Lignite Inventory Levels.

**1.3.1.2 Items Not Considered Protected Information**

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

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

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

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

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

(e) Status of RMR Units;

(f) Black Start Agreements;

(g) FFSS awards;

(h) RMR Settlement charges and payments;

|  |
| --- |
| ***[NPRR885: Insert items (i) and (j) below upon system implementation and renumber accordingly:]***  (i) Must-Run Alternative (MRA) Agreements;  (j) Settlement charges and payments for MRA Service; |

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

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

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

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

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (1) above with the following upon system implementation:]***  (1) Interconnection of new Generation Resources, Energy Storage Resources (ESRs), Settlement Only Generators (SOGs), or Settlement Only Energy Storage Systems (SOESSs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents. |

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (2) above with the following upon system implementation:]***  (2) For existing Generation Resources, ESRs, 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, ESRs, 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, ESRs, 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, ESRs, 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, ESR, or SOTSG is electrically connected.

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

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

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

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

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

## 2.1 DEFINITIONS

**Blackout**

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

***Partial Blackout***

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

**Credible Single Contingency**

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

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

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

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

**Emergency Response Service (ERS) Generator**

Either (1) an individual generator contracted to provide ERS which is neither a Generation Resource, nor a source of intermittent renewable generation, nor an Energy Storage Resource (ESR) and which provides ERS by injecting energy to the ERCOT System, or (2) an aggregation of such generators.

**ERCOT System Demand**

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

|  |
| --- |
| [NPRR1013: Insert the following definition “Frequency Responsive Capacity (FRC)” upon system implementation of the Real-Time Co-Optimization (RTC) project:]  **Frequency Responsive Capacity (FRC)**  The telemetered portion of the total MW output of a Generation Resource or Energy Storage Resource (ESR) that represents the fraction of the capacity that is capable of providing Primary Frequency Response. Capacity not capable of providing Primary Frequency Response includes, but may not be limited to, capacity from duct firing, auxiliary boilers, and other methods that do not immediately respond, arrest, or stabilize frequency excursions following a disturbance without secondary frequency response or instructions from ERCOT. |

Generation Entity

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

|  |
| --- |
| ***[NPRR995: Replace the above definition “Generation Entity” with the following upon system implementation:]***  **Generation Entity**  The owner of a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) and, unless otherwise specified in these Protocols, is registered as a Resource Entity. |

**Initial Energization**

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

|  |
| --- |
| ***[NPRR995: Replace the above definition “Initial Energization” with the following upon system implementation:]***  **Initial Energization**  The first time a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) facility’s equipment connects to the ERCOT System during commissioning. |

**Initial Synchronization**

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

|  |
| --- |
| ***[NPRR995: Replace the above definition “Initial Synchronization” with the following upon system implementation:]***  **Initial Synchronization**  The first time a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) facility’s new equipment injects power to the ERCOT System during commissioning. |

Load Frequency Control (LFC)

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

Meter Reading Entity (MRE)

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

**Must-Run Alternative (MRA)**

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

|  |
| --- |
| ***[NPRR885 and NPRR995: Replace applicable portions of the above definition “Must-Run Alternative (MRA)” with the following upon system implementation:]***  **Must-Run Alternative (MRA)**  A resource operated under the terms of an Agreement with ERCOT as an alternative to a Reliability Must-Run (RMR) Unit. An MRA may be one of the following:  ***Generation Resource MRA***  A generator that is registered with ERCOT as a Generation Resource that is dispatchable in Security-Constrained Economic Dispatch (SCED) and is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT.  Energy Storage Resource MRA  An Energy Storage Resource that is registered with ERCOT as an Energy Storage Resource that is dispatchable in Security-Constrained Economic Dispatch (SCED) and is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT.  ***Other Generation MRA***  Unregistered generation, or generation registered with ERCOT that is not dispatchable in Security-Constrained Economic Dispatch (SCED), that is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT. An Other Generation MRA may include, but is not limited to, Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Distributed Generation (DG).  ***Demand Response MRA***  A Load providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT by reducing energy consumption in response to an ERCOT instruction. A Demand Response MRA may be an unregistered Load or a registered Load Resource other than a Controllable Load Resource.  ***Weather-Sensitive MRA***  A type of Must-Run Alternative (MRA) Service in which a Demand Response MRA provides MRA Service only after meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1, Emergency Response Service Procurement. |

|  |
| --- |
| ***[NPRR885: Insert the following definition “Must-Run Alternative (MRA) Contracted Hour(s)” upon system implementation:]***  **Must-Run Alternative (MRA) Contracted Hour(s)**  The hour(s) during which an MRA is contracted under an MRA Agreement to provide MRA Service. |

**Outage**

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

***Forced Outage***

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

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

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

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

***Maintenance Outage***

An Outage initiated manually to remove equipment from service to perform work on components that could be postponed briefly but that is required to prevent a potential Forced Outage and that cannot be postponed until the next Planned Outage. Maintenance Outages are classified as follows:

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

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

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

***Opportunity Outage***

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

***Planned Outage***

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

***Rescheduled Outage***

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

***Simple Transmission Outage***

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

Power System Stabilizer (PSS)

A device or control that is installed on a synchronous machine to provide oscillation dampening support to the ERCOT System under transient conditions.

**Resource**

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

|  |
| --- |
| ***[NPRR995: Replace the above definition “Resource” with the following upon system implementation:]***  **Resource**  The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term “Resource” used by itself in these Protocols does not include a Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or an Emergency Response Service (ERS) Resource. |

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

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

|  |
| --- |
| ***[NPRR1029: Insert the following definition “DC-Coupled Resource upon system implementation:]***  ***DC-Coupled Resource***  A type of Energy Storage Resource (ESR) in which an Energy Storage System (ESS) is combined with wind and/or solar generation in the same modeled generation station and interconnected at the same Point of Interconnection (POI), and where these technologies are interconnected within the site using direct current (DC) equipment. The combined technologies are then connected to the ERCOT System using the same direct current-to-alternating current (DC-to-AC) inverter(s). To be classified as a DC-Coupled Resource, the generator(s) and ESS(s) at a site must meet the following conditions:  (1) The ESS component of the Resource must have a nameplate rating of at least ten MW and ten MWh, or the MW rating must equal or exceed 50% of the nameplate MW rating of the inverter; and  (2) All intermittent renewable generators must meet the conditions for aggregation stated in paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, except to the extent any such condition requires the generator to be a Resource. |

***Distribution Energy Storage Resource (DESR)***

An Energy Storage Resource (ESR) connected to the Distribution System that is either:

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

(2) Greater than one MW that chooses to register as a Resource with ERCOT to participate in the ERCOT markets.

***Transmission Energy Storage Resource (TESR)***

An Energy Storage Resource (ESR) 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 Resource with ERCOT to participate in the ERCOT markets.

***Generation Resource***

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

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

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

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

(2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets.

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

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

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

(2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets.

***Load Resource***

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

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

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

***Controllable Load Resource***

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

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

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

|  |
| --- |
| ***[NPRR995: Delete the above definition “Settlement Only Generator (SOG)” upon system implementation.]*** |

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

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

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

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

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

|  |
| --- |
| ***[NPRR995: Delete the above definition “Settlement Only Distribution Generator (SODG)” upon system implementation.]*** |

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

A generator that is connected to the ERCOT transmission system with a rating of ten MW or less and is registered with the Public Utility Commission of Texas (PUCT) as a power generation company. SOTGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and may be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

|  |
| --- |
| ***[NPRR995: Delete the above definition “Settlement Only Transmission Generator (SOTG)” upon system implementation.]*** |

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

A generator that is connected to the ERCOT transmission system with a rating of one MW or more and is registered with the Public Utility Commission of Texas (PUCT) as a self-generator. SOTSGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.3, Modeling of Private Use Networks.

|  |
| --- |
| ***[NPRR995: Delete the above definition “Settlement Only Transmission Self-Generator (SOTSG)” upon system implementation.]*** |

**Resource Attribute**

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

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

A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are located behind the same Main Power Transformer (MPT).

***Black Start Resource***

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

***Combined Cycle Train***

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

***Decommissioned Generation Resource***

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

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

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

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

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

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

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

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

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

***Inverter-Based Resource (IBR)***

A Resource that is connected to the ERCOT System either completely or partially through a power electronic converter interface.

***Mothballed Generation Resource***

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

***Mothballed Energy Storage Resource***

An Energy Storage Resource (ESR) 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.

Seasonal Operation Period

The period in which a Generation Resource or Energy Storage Resource (ESR) has identified it is available for operation.

**Subsynchronous Oscillation (SSO)**

Coincident oscillation occurring between two or more Transmission Elements, Generation Resources, or Energy Storage Resources (ESRs) at a natural harmonic frequency lower than the normal operating frequency of the ERCOT System (60 Hz).

***Subsynchronous Resonance (SSR)***

Coincident oscillation occurring between Generation Resources or Energy Storage Resources (ESRs) and a series capacitor compensated transmission system at a natural harmonic frequency lower than the normal operating frequency of the ERCOT System (60 Hz), including the following types of interactions:

***Torsional Interaction***

Torsional Interaction is the interplay between mechanical system of a turbine generator and a series compensated transmission system.

***Induction Generator Effect (IGE)***

An electrical phenomena in which a resonance involving a Generation Resource or ESR and a series compensated transmission system results in electrical self-excitation of the Generation Resource at a subsynchronous frequency.

***Torque Amplification***

An interaction between Generation Resources or ESRs and a series compensated transmission system in which the response results in higher transient torque during or after disturbances than would otherwise occur.

***Subsynchronous Control Interaction (SSCI)***

The interaction between a series capacitor compensated transmission system and the control system of Generation Resources or ESRs.

**Subsynchronous Resonance (SSR) Countermeasures**

Any equipment or any procedure to mitigate the SSR vulnerability, including but not limited to the following types of countermeasures:

***Subsynchronous Resonance* (*SSR) Protection***

A countermeasure that includes, but is not limited to, disconnecting the affected Generation Resource or Energy Storage Resource (ESR).

***Subsynchronous Resonance* (*SSR) Mitigation***

A countermeasure that includes, but is not limited to, equipment installation, controller adjustment, or a procedure to mitigate the SSR vulnerability without disconnecting the affected Generation Resources or ESRs.

Unit Reactive Limit (URL)

The maximum quantity of Reactive Power that a Generation Resource or Energy Storage Resource (ESR) is capable of providing at a 0.95 power factor at its maximum real power capability.

## 2.2 ACRONYMS AND ABBREVIATIONS

**TESR** Transmission Energy Storage Resource

***3.1.1 Role of ERCOT***

(1) ERCOT shall coordinate and use reasonable efforts, consistent with Good Utility Practice, to accept, approve or reject all requested Outage plans for maintenance, repair, and construction of both Transmission Facilities and Resources within the ERCOT System. ERCOT may reject an Outage plan under certain circumstances, as set forth in these Protocols.

(2) ERCOT’s responsibilities with respect to Outage Coordination include:

(a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) in coordination with and based on information regarding all Entities’ Planned Outages and Maintenance Outages;

|  |
| --- |
| ***[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) and Direct Current Tie Operators (DCTOs) in coordination with and based on information regarding all Entities’ Planned Outages and Maintenance Outages; |

(b) Assessing the adequacy of available Resources, based on planned and known Resource Outages, relative to forecasts of Load, Ancillary Service requirements, and reserve requirements;

(c) Coordinating all Planned Outage and Maintenance Outage plans and approving or rejecting Outage plans for Planned Outages of Resources;

(d) Coordinating and approving or rejecting Outage plans for Planned Outages of Reliability Must-Run (RMR) Units under the terms of the applicable RMR Agreements;

(e) Coordinating and approving or rejecting Outage plans associated with Black Start Resources under the applicable Black Start Unit Agreements;

(f) Coordinating and approving or rejecting Outage plans affecting Subsynchronous Resonance (SSR) vulnerable Generation Resources and Energy Storage Resources (ESRs) that do not have SSR Mitigation in the event of five or six concurrent transmission Outages;

(g) Coordinating and approving or rejecting changes to existing Resource Outage plans;

(h) Monitoring how Planned Outage schedules compare with actual Outages;

(i) Posting all proposed and approved schedules for Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities on the Market Information System (MIS) Secure Area under Section 3.1.5.13, Transmission Report;

(j) Creating and posting aggregated MW of Planned Outages for Resources on the MIS Secure Area under Section 3.2.3, Short-Term System Adequacy Reports;

(k) Monitoring Transmission Facilities and Resource Forced Outages and Maintenance Outages of immediate nature and implementing responses to those Outages as provided in these Protocols;

(l) Establishing and implementing communication procedures:

(i) For a TSP to request approval of Transmission Facilities Planned Outage and Maintenance Outage plans; and

|  |
| --- |
| ***[NPRR857: Replace item (i) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (i) For a TSP or a DCTO to request approval of Transmission Facilities Planned Outage and Maintenance Outage plans; and |

(ii) For a Resource Entity’s designated Single Point of Contact to submit Outage plans and to coordinate Resource Outages;

(m) Establishing and implementing record-keeping procedures for retaining all requested Planned Outages, Maintenance Outages, Rescheduled Outages, and Forced Outages; and

(n) Planning and analyzing Transmission Facilities Outages.

**3.1.3.2 Resources**

(1) Each Resource Entity shall provide to ERCOT a Planned Outage and Maintenance Outage plan for Generation Resources and ESRs in an ERCOT-provided format for at least the next 12 months updated monthly. Planned Outage and Maintenance Outage plans must be updated as soon as practicable following any change. Updates, through an electronic interface as specified by ERCOT, must identify any changes to previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outages.

(2) ERCOT shall report statistics monthly on how Resource Planned Outages compare with actual Resource Outages, and post those statistics to the MIS Secure Area.

**3.1.4.5 Notice of Forced Outage or Unavoidable Extension of Planned, Maintenance, or Rescheduled Outage Due to Unforeseen Events**

(1) If a Planned, Maintenance, or Rescheduled Outage is not completed within the ERCOT-approved timeframe and the Transmission Facilities or Resources are in such a condition that they cannot be restored at the Outage schedule completion date, the requesting party shall submit to ERCOT a Forced Outage (unavoidable extension) form describing the extension of the Outage and providing a revised return date.

(2) Any transmission Forced Outage that occurs in Real-Time and that is expected to continue for longer than two hours must be entered into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Outage. Any transmission Forced Outage with a duration exceeding two hours must be entered into the Outage Scheduler as soon as practicable but no longer than 150 minutes after the beginning of the transmission Forced Outage, if not already reported in the Outage Scheduler.

(3) Any Resource Forced Outage that occurs in Real-Time must be entered into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Forced Outage.

(4) If the QSE is to receive the exemption described in paragraph (6)(d) of Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics, the QSE will notify ERCOT Operators by voice communication of every Forced Outage, Forced Derate, or Startup Loading Failure within 15 minutes.

(5) For a Startup Loading Failure, the Resource Entity or its designee must enter a Forced Outage in the Outage Scheduler if the Resource was in an Off-Line status prior to the Startup Loading Failure or update the existing Outage for the Resource if the Resource was on Outage prior to the Startup Loading Failure. The Resource Entity or its designee must also provide a text entry in the supporting information field of the Outage Scheduler that includes the following:

(a) A statement that a Startup Loading Failure occurred;

(b) An explanation of the cause of the Startup Loading Failure using the best available information at the time the Outage or update to the existing Outage is entered, which must be updated if more accurate information becomes available; and

(c) The start time and end time of the Startup Loading Failure portion of the Outage.  Multiple consecutive startup attempts may be aggregated into a single Startup Loading Failure event with a single start and end time.

**3.1.5.1 ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities**

(1) A TSP or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP requests, the TSPs shall enter such requests in the Outage Scheduler. For Resource Entity requests, the Resource Entity shall enter such requests in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP enters the breaker and switch statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP or Resource Entity in accordance with this Section constitutes a request for ERCOT’s approval of the Outage Schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests.

|  |
| --- |
| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) A TSP, DCTO, or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP, DCTO, and Resource Entity requests, the requesting Entity shall enter such a request in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP or DCTO enters the breaker and switch statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP, DCTO, or Resource Entity in accordance with this Section constitutes a request for ERCOT’s approval of the Outage Schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP, DCTO, or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests. |

(2) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules. ERCOT shall transmit its approvals and rejections to TSPs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities.

|  |
| --- |
| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules. ERCOT shall transmit its approvals and rejections to TSPs and DCTOs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities. |

(3) Private Use Network Outage requests submitted pursuant to this Section shall not be publicly posted.

(4) To the extent authorized by its tariff, an External Load Serving Entity (ELSE) or Non-Opt-In Entity (NOIE) that provides retail service to a Resource Entity that owns or operates a Generation Resource or ESR may request that the TSP to which the Resource is interconnected disconnect the Resource due to the Resource Entity’s failure to comply with the payment requirements in the ELSE’s or NOIE’s retail tariff.

(5) Within five Business Days after receiving a request from a Load Serving Entity (LSE) to disconnect a Generation Resource or ESR due to the Resource Entity’s failure to comply with LSE’s payment requirements, including a request received pursuant to paragraph (4) above, the interconnecting TSP shall enter a request in the Outage Scheduler for an Outage of any Transmission Facilities interconnecting the Resource to the ERCOT System. Any Outage requested or taken pursuant to this Section shall be treated as a Planned Outage for all purposes under the Protocols. For any such Outage request, the requesting TSP shall enter a start date that it is at least four days after the date the request is submitted in the Outage Scheduler and shall enter an Outage end date that is 14 days from the date of the requested start date. Unless storm or system reliability issues prevent immediate dispatch of personnel, for any LSE request to reconnect a Customer that was disconnected pursuant to this section, the interconnecting TSP shall end the Outage and reconnect the Resource the same Business Day if the request is received by 1200, or the next Business Day if the request is received after 1200. If a reconnect request is not received within four days of the Outage end date, the interconnecting TSP shall enter another request in the Outage Scheduler for an Outage of any Transmission Facilities interconnecting the Resource to the ERCOT System with an Outage end date 14 days beyond the prior Outage end date. At any time, ERCOT may withdraw approval of the Outage and instruct the TSP to reconnect the Resource if it deems cancellation necessary to address reliability concerns.

**3.1.5.11 Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests**

(1) ERCOT shall evaluate requests, approve, or reject Transmission Facilities Planned Outages and Maintenance Outages according to the requirements of this section. ERCOT may approve Outage requests provided the Outage in combination with other proposed Outages does not cause a violation of applicable reliability standards. ERCOT shall reject Outage requests that do not meet the submittal timeline specified in Section 3.1.5.12, Submittal Timeline for Transmission Facility Outage Requests. ERCOT shall consider the following factors in its evaluation:

(a) Forecasted conditions during the time of the Outage;

(b) Outage plans submitted by Resource Entities and TSPs under Section 3.1, Outage Coordination;

|  |
| --- |
| ***[NPRR857: Replace item (b) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (b) Outage plans submitted by Resource Entities, TSPs, and DCTOs under Section 3.1, Outage Coordination; |

(c) Forced Outages of Transmission Facilities;

(d) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software;

(e) Potential for the proposed Outages to cause SSR vulnerability to Generation Resources or ESRs that do not have SSR Mitigation in the event of five or six concurrent transmission Outages;

(f) Previously approved Planned Outages, Maintenance Outages, and Rescheduled Outages;

(g) Impacts on the transfer capability of Direct Current Ties (DC Ties); and

(h) Good Utility Practice for Transmission Facilities maintenance.

(2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP.

|  |
| --- |
| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP or DCTO. |

(3) When ERCOT identifies that an HIO has been submitted with 90-days or less notice, ERCOT may coordinate with TSP to make reasonable efforts to minimize the impact.

|  |
| --- |
| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) When ERCOT identifies that an HIO has been submitted with 90-days or less notice, ERCOT may coordinate with the TSP or DCTO to make reasonable efforts to minimize the impact. |

***3.6.1 Load Resource Participation***

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

(i) Regulation Up (Reg-Up) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(ii) Regulation Down (Reg-Down) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(iii) Responsive Reserve (RRS) as a Controllable Load Resource qualified for Security-Constrained Economic Dispatch (SCED) Dispatch and capable of providing Primary Frequency Response, or as a Load Resource controlled by high-set under-frequency relay;

(iv) ERCOT Contingency Reserve Service (ECRS) as a Controllable Load Resource qualified for SCED Dispatch and capable of providing Primary Frequency Response, or as a Load Resource that may or may not be controlled by high-set under-frequency relay;

|  |
| --- |
| ***[NPRR1244: Replace paragraph (iv) above with the following upon system implementation:]***  (iv) ERCOT Contingency Reserve Service (ECRS) as a CLR qualified for SCED Dispatch, or as a Load Resource that may or may not be controlled by high-set under-frequency relay; |

(v) Non-Spinning Reserve (Non-Spin) as a Controllable Load Resource qualified for SCED Dispatch or as a Load Resource that is not a Controllable Load Resource and that is not controlled by under-frequency relay; and

(vi) A Load Resource that is not a Controllable Load Resource cannot simultaneously provide Non-Spin and RRS in Real-Time;

(b) Energy in the form of Demand response from a Controllable Load Resource in Real-Time via SCED;

(c) Emergency Response Service (ERS) for hours in which the Load Resource does not have an Ancillary Service Resource Responsibility; and

|  |
| --- |
| ***[NPRR1007: Replace paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (c) Emergency Response Service (ERS) for hours in which the Load Resource has a Resource Status of OUTL; and |

(d) Voluntary Load response in Real-Time.

(2) Except for voluntary Load response and ERS, loads participating in any ERCOT market must be registered as a Load Resource and are subject to qualification testing administered by ERCOT.

(3) All ERCOT Settlements resulting from Load Resource participation are made only with the Qualified Scheduling Entity (QSE) representing the Load Resource.

(4) A QSE representing a Load Resource and submitting a bid to buy for participation in SCED, as described in Section 6.4.3.1, RTM Energy Bids, must represent the Load Serving Entity (LSE) serving the Load of the Load Resource. If the Load Resource is an Aggregate Load Resource (ALR), the QSE must represent the LSE serving the Load of all sites within the ALR.

(5) The Settlement Point for a Controllable Load Resource is its Load Zone Settlement Point.

|  |
| --- |
| ***[NPRR1188: Replace paragraph (5) above with the following upon system implementation:]***  (5) The Settlement Point for a CLR that is not an ALR is its Resource Node Settlement Point. The Settlement Point for an ALR is its Load Zone Settlement Point. For an Energy Storage Resource (ESR), the Settlement Point for the charging Load withdrawn by the modeled CLR associated with the ESR is the Resource Node of the modeled Generation Resource associated with the ESR. |

(6) QSEs shall not submit offers for Load Resources containing sites associated with a Dynamically Scheduled Resource (DSR).

|  |
| --- |
| ***[NPRR1000: Delete paragraph (6) above upon system implementation and renumber accordingly.]*** |

(7) Each Resource Entity that represents one or more Load Resources shall ensure that each Load Resource it represents meets at least one of the following conditions:

(a) The Load Resource is not located behind an Electric Service Identifier (ESI ID) that corresponds to a Critical Load;

(b) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but the Load Resource is not a Critical Load and does not include a Critical Load; or

(c) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site.

(8) As a condition of obtaining and maintaining registration as a Load Resource, the Resource Entity for the Load Resource must have submitted an attestation, in a form deemed acceptable by ERCOT, stating that one of the conditions set forth in paragraph (7) above is true, and that if either of the conditions in paragraph (7)(b) or (7)(c) is true, then all of the Load Resource’s offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(9) Each QSE that represents one or more ERS Resources shall ensure that each ERS Resource identified in any ERS Submission Form submitted by the QSE meets at least one of the following conditions:

(a) The ERS Resource and each site within the ERS Resource are not located behind an ESI ID or unique meter identifier that corresponds to a Critical Load and are not used to support a Critical Load; or

(b) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but the ERS Resource and each site within the ERS Resource are not a Critical Load, do not include a Critical Load, and are not used to support a Critical Load; or

(c) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site, and neither the ERS Resource nor any site within the ERS Resource is used to support a Critical Load.

***3.8.5 Energy Storage Resources***

(1) A QSE representing an ESR may update the telemetered HSL and/or Maximum Power Consumption (MPC) for the ESR in Real-Time to ensure the ability to meet the ESR’s full Ancillary Service Resource Responsibility for the current Operating Hour. This provision only applies when the MOC for an ESR is set at the System-Wide Offer Cap (SWCAP) pursuant to paragraph (1)(b) of Section 4.4.9.4.1, Mitigated Offer Cap.

|  |
| --- |
| ***[NPRR1075: Delete paragraph (1) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]*** |

(2) A QSE representing an ESR may update the telemetered HSL and/or MPC for the ESR in Real-Time to reflect state of charge limitations.

|  |
| --- |
| ***[NPRR1075: Replace paragraph (2) above with the following upon system implementation of NPRR1014:]***  (2) A QSE representing an ESR may update the telemetered HSL and/or LSL for the ESR in Real-Time to reflect state of charge limitations. |

(3) A QSE representing an ESR co-located with a Generation Resource may reduce the telemetered MPC of the Controllable Load Resource modeled to represent the charging side of the ESR when self-charging using output from the Generation Resource. Such reduction in MPC shall be equal to the MW level of self-charge.

|  |
| --- |
| ***[NPRR1075: Replace paragraph (3) above with the following upon system implementation of NPRR1014:]***  (3) A QSE representing an ESR co-located with a Generation Resource may update the telemetered LSL of the ESR when self-charging (using output from the Generation Resource). The updated LSL shall be equal to the MW level of self-charge. |

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

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

|  |
| --- |
| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs, DCTOs, and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates. |

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (2) above with the following upon system implementation:]***  (2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource, Settlement Only Generator (SOG), or Settlement Only Energy Storage System (SOESS) as described in Planning Guide Section 5, Generator Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource, SOG, or SOESS. |

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

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

Notes:

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

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

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

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

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

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

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

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

***3.10.3 CRR Network Model***

(1) ERCOT shall develop models for Congestion Revenue Right (CRR) Auctions that contain, as much as practicable, information consistent with the Network Operations Model. Names of Transmission Elements in the Network Operations Model and the CRR Network Model must be identical for the same physical equipment.

(2) ERCOT shall verify that the names of Hub Buses and Electrical Buses used to describe the same device in any Hub are identically named in both the Network Operations Model and the CRR Network Model.

(3) Each CRR Network Model must include:

(a) A system-wide diagram including all modeled Transmission Elements (except those within Private Use Networks) and Resource Nodes;

(b) Station one-line diagrams for all Settlement Points (indicating the Settlement Point that the Electrical Bus is a part of) and including all Hub Buses used to calculate Hub prices (if applicable), except those within Private Use Networks;

(c) Generation Resource and ESR locations;

(d) Transmission Elements;

(e) Transmission impedances;

(f) Transmission ratings, excluding Relay Loadability Ratings;

(g) Contingency lists;

(h) Data inputs used in the calculation of Dynamic Ratings, and

(i) Other relevant assumptions and inputs used for the CRR Network Model.

(4) ERCOT shall make available to TSPs and/or DSPs and all appropriate Market Participants, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, the CRR Network Model. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web based XML communications or PSS/E format.

***3.10.6 QSE and Resource Entity Responsibilities***

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (1) above with the following upon system implementation:]***  (1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation Resource, SOG, SOESS, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads. |

(2) QSEs shall ensure availability of telemetry to generation and transmission equipment its Resource Entity owns at ERCOT’s request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5, Telemetry Requirements. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) For each Generation Resource and Energy Storage Resource (ESR), Resource Entities shall provide ERCOT the following temperature data:

(a) Cold weather temperature limits:

(i) Minimum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without a Forced Outage or Startup Loading Failure due to cold weather after at least one complete winter Peak Load Season following the Resource’s Initial Synchronization date based on the previous five calendar years of historical data; and

(ii) Minimum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum rating due to cold weather after at least one complete winter Peak Load Season following the Resource’s Initial Synchronization date based on the previous five calendar years of historical data; and

(iii) At least one of the following:

(A) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum sustainable rating; or

(B) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum sustainable rating determined by an engineering analysis; and

(iv) At least one of the following:

(A) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Outage or Startup Loading Failure; or

(B) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Outage or Startup Loading Failure determined by an engineering analysis.

(b) Hot weather temperature limits:

(i) Maximum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Outage or Startup Loading Failure due to hot weather after at least one complete summer Peak Load Season following the Resource’s Initial Synchronization date based on the previous five years of historical data; and

(ii) Maximum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating due to hot weather after at least one complete summer Peak Load Season following the Resource’s Initial Synchronization date based on the previous five calendar years of historical data; and

(iii) At least one of the following:

(A) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating; or

(B) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating, determined by an engineering analysis; and

(iv) At least one of the following:

(A) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Outage or Startup Loading Failure; or

(B) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Outage or Startup Loading Failure, determined by an engineering analysis.

(4) Each Resource Entity shall review at least annually the temperatures described in paragraphs (3)(a)(i), (3)(a)(ii), (3)(b)(i), and (3)(b)(ii) above and shall update each Resource’s Registration data within 30 days of identifying any change in these temperatures.

(5) Each Resource Entity shall review at least once every seven years the temperatures described in paragraphs (3)(a)(iii), (3)(a)(iv), (3)(b)(iii), and (3)(b)(iv) above and shall update each Resource’s Registration data within 30 days of identifying any change in these temperatures.

(6) Resource Entities shall update each Generation Resource’s alternate fuel information within 30 days of any changes to the alternate fuel information.

***3.10.7.1.4 Transmission, Main Power Transformers (MPTs) and Generation Step-Up Transformers***

(1) ERCOT shall model all transformers with a nominal low side (i.e., secondary, not tertiary) voltage above 60 kV.

(2) For Generation Resources and ESRs, ERCOT shall model all Main Power Transformers (MPTs) and Generator Step-Up (GSU) transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under Load, accept telemetry of the current tap position.

(3) Each TSP and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

|  |
| --- |
| ***[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (3) Each TSP, DCTO, and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters: |

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Winding ratings, including Normal Rating, Emergency Rating, 15-Minute Rating, Conductor/Transformer 2-Hour Rating, and Relay Loadability Rating;

(f) Connectivity;

(g) Transformer parameters, including all tap parameters; and

(h) Other data necessary to model Transmission Element(s).

(4) The Resource Entity shall provide parameters for each MPT to ERCOT as part of the Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process. ERCOT shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to establish the proper transformer tap positions (no-load taps) and the equipment owner shall report any changes to ERCOT using the NOMCR process or other ERCOT prescribed means. Each Resource Entity and each TSP shall schedule generation Outages at mutually agreeable times to implement tap position changes when necessary. If mutual agreement cannot be reached, then ERCOT shall decide where to set the tap position to be implemented by the Resource Entity at the next generation Outage, considering expected impact on system security, future Outage plans, and participants. TSPs shall provide ERCOT and Market Participants with notice in accordance with paragraph (4) of Section 3.10.4, ERCOT Responsibilities, (except for emergency) prior to the tap position change implementation date.

(5) ERCOT shall post to the MIS Secure Area information regarding all transformers represented in the Network Operations Model.

**3.10.7.2 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, ESRs, SOGs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), ESRs connected at transmission voltage, Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), 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, ESRs, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

|  |
| --- |
| ***[NPRR995: 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, ESRs, SOGs, SOESSs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Transmission ESRs (TESR), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), and the non-TSP MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, ESRs, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models. |

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

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

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (4) above with the following upon system implementation:]***  (4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) or Settlement Only Distribution Energy Storage System (SODESS) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG or SODESS facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG or SODESS facilities to their appropriate Load in the Network Operations Model. |

(5) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility MPT.

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

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

|  |
| --- |
| ***[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (7) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define “Model Loads”, which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones. |

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

|  |
| --- |
| ***[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (8) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request. |

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

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

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

(12) If the Day-Ahead Market (DAM) determines, in the processing of Outages, that a Load Resource, DGR, or DESR is de-energized in the ERCOT Network Operations Model, the de-energized Resource will be eligible to receive Ancillary Service awards in the DAM, but will not be eligible to receive energy awards in the DAM.

(13) A Resource Entity may aggregate Intermittent Renewable Resource (IRR) generation equipment together to form an IRR (Wind-powered Generation Resource (WGR) or PhotoVoltaic Generation Resource (PVGR)) if the generation equipment is behind the same main power transformer and is the same model and size, and the aggregation does not reduce ERCOT’s ability to model pre- and post-contingency conditions. A Resource Entity may also aggregate IRR generation equipment that is not the same model and size together with an existing IRR only if:

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

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

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

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

(e) Either:

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

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

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

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

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

**3.10.7.6 Use of Generic Transmission Constraints and Generic Transmission Limits**

(1) For the sole purpose of creating transmission flow constraints between areas of the ERCOT Transmission Grid in ERCOT applications that are unable to recognize non-thermal operating limits (such as system stability limits and voltage limits on Electrical Buses), ERCOT may create new Generic Transmission Constraints (GTCs) or modify existing GTCs for use in reliability and market analysis. GTCs created or modified as described in this Section shall be used in the SCED application. ERCOT shall not use GTCs in ERCOT applications to replace other constraints already capable of being directly modeled in the SCED application.

(2) During the ERCOT quarterly stability assessment, performed pursuant to Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if ERCOT determines a GTC is necessary for a new Generation Resource, ESR, or SOTSG due to localized stability issues associated with the output of the interconnecting Generation Resource, ESR, or SOTSG, the GTL for the GTC shall be set to the lowest non-zero limit for all system conditions outside those in which the limit is zero.

(3) Except as provided in paragraph (6) below, ERCOT shall post a description of each new or modified GTC to the MIS Secure Area as soon as possible, but no later than the day prior to the GTC or GTC modification becoming effective in any ERCOT application. Posting of each new or modified GTC shall include:

(a) The description of the new or modified GTC including the GTL or description of the data and studies used to calculate the GTL associated with each new or modified GTC;

(b) The effective date of the new or modified GTC;

(c) The identity of all constrained Transmission Elements that make up the GTC, including the defined interface where applicable; and

(d) Detailed information on the development of each GTC, including the defined constraint or interface where applicable; and data and studies used for development of each new or modified GTC, including the GTL associated with each new or modified GTC. This information shall be redacted or omitted to protect the confidentiality of certain stability-related GTCs.

(4) Market Participants may review and comment on each new or modified GTC. Within seven days following receipt of any comments, ERCOT shall post the comments to the MIS Secure Area as part of the information related to the subject GTC. ERCOT shall review any comments and may modify any part of a given GTC in response to any comments received.

(5) Anticipated GTLs, except those determined pursuant to paragraph (6) below, shall be posted to the MIS Secure Area no later than one day before the Operating Day.

(6) If an unexpected change to ERCOT System conditions requires the creation of a new GTC or the modification of an existing GTC to manage ERCOT System reliability, and the GTC has not been posted pursuant to paragraph (3) above, ERCOT shall issue an Operating Condition Notice (OCN) and post on the MIS Secure Area the new or modified GTC and its associated GTL(s), including the detailed information described in paragraphs (3) and (5) above. ERCOT shall include an explanation regarding why it did not post the GTC or modification on the previous day.

(7) No later than 180 days after the effective date of a new GTC, ERCOT shall post a report listing alternatives for exiting the GTC to the MIS Secure Area. The listed alternatives may include but are not limited to the implementation or modification of a RAS or a transmission improvement project.

**3.10.7.7** **DC Tie Limits**

(1) ERCOT shall post DC Tie limits for each hour of the Operating Day to the MIS Secure Area no later than 0600 in the Day-Ahead before the Operating Day. ERCOT may update these limits as system conditions change.

(2) DC Tie limits shall be based on expected system conditions, including Outages, for each hour of the Operating Day and shall be calculated as the lower of the physical capacity of the DC Tie, the amount of DC Tie import and export that could flow without resulting in transmission security violations that would not be resolved by SCED, or, for the DC Ties with Mexico, any limits supplied by the Mexican system operator. In setting these limits for a given hour, ERCOT shall assume that any Generation Resource or ESR shown to be available in its COP will be self-committed or committed at the appropriate time through the Reliability Unit Commitment (RUC) process to resolve any transmission constraints resulting from DC Tie Schedules. DC Tie Schedules are subject to the actual availability of that generation at the time the Generation Resource or ESR is needed, as well as other system conditions.

|  |
| --- |
| ***[NPRR825: Replace Section 3.10.7.7 above with the following upon system implementation:]***  **3.10.7.7** **DC Tie Advisory Limits**  (1) Every hour, ERCOT shall post DC Tie advisory limits for each hour of the next 48 hours to the MIS Secure Area. ERCOT may update these limits as system conditions change. Any updated DC Tie advisory limits shall be posted to the MIS Secure Area as soon as practicable.  (2) DC Tie advisory limits shall be based on expected, or actual system conditions, including Outages, for each hour of the Operating Day and shall be calculated as the lower of the available physical capacity of the DC Tie, the amount of DC Tie import and export that could flow without resulting in transmission security violations that would not be resolved by SCED, or, for the DC Ties with Mexico, any limits supplied by the Mexican system operator. In setting these limits for a given hour, ERCOT shall assume that any Generation Resource or ESR shown to be available in its COP for a given hour will be self-committed or committed at the appropriate time through the Reliability Unit Commitment (RUC) process to resolve any transmission security violations resulting from DC Tie Schedules. DC Tie Schedules are subject to the actual availability of that generation at the time the Generation Resource or ESR is needed, as well as other system conditions. |

**3.14.1.9 Generation Resource/Energy Storage Resource Status Updates**

(1) By April 1st and October 1st of each year and when material changes occur, every Resource Entity that owns or controls a Mothballed Generation Resource, a Mothballed Energy Storage Resource (ESR), or an RMR Unit shall report to ERCOT, on a unit-specific basis, the estimated lead time required for each Resource to be capable of returning to service and, in percentage terms, report probable generation capacity from each Resource that the Resource Entity expects to return to service in each Season of each of the next ten years.

(2) For modeling purposes, ERCOT and TSPs shall rely on the most recent submittal of the following two Notifications with respect to an RMR Unit, Mothballed Generation Resource, Mothballed ESR, or Decommissioned Generation Resource: Section 22, Attachment E, Notification of Suspension of Operations, or Section 22, Attachment H, Notification of Change of Resource Designation. Except in the case of an NSO submitted for a Resource temporarily suspending operation due to a Forced Outage, ERCOT shall post each submitted NSO and Notification of Change of Resource Designation to the MIS Secure Area and issue a Market Notice notifying Market Participants of the posting as soon as practicable, but no later than five Business Days after receipt.

|  |
| --- |
| ***[NPRR1183: Replace paragraph (2) above with the following upon system implementation:]***  (2) For modeling purposes, ERCOT and TSPs shall rely on the most recent submittal of the following two Notifications with respect to an RMR Unit, Mothballed Generation Resource, Mothballed ESR, or Decommissioned Generation Resource: Section 22, Attachment E, Notification of Suspension of Operations, or Section 22, Attachment H, Notification of Change of Resource Designation. Except in the case of an NSO submitted for a Resource temporarily suspending operation due to a Forced Outage, ERCOT shall post each submitted NSO and Notification of Change of Resource Designation to the ERCOT website and issue a Market Notice notifying Market Participants of the posting as soon as practicable, but no later than five Business Days after receipt. |

(3) A Mothballed Generation Resource or Mothballed ESR that is not mothballed indefinitely shall remain modeled in all ERCOT systems at all times, (i.e., will not be flagged as “mothballed” in ERCOT’s models) and, when it is not available, the Resource Entity shall designate the Resource as on Planned Outage in the Outage Scheduler.

(4) Except for Mothballed Generation Resources and Mothballed ESRs that operate under a Seasonal Operation Period, a Resource Entity with a Mothballed Generation Resource or Mothballed ESR shall notify ERCOT in writing no less than 30 days prior to the date on which the Resource Entity intends to return a Mothballed Generation Resource or Mothballed ESR to service by completing a Notification of Change of Resource Designation.

(5) A Resource Entity must submit a Notification of Change of Resource Designation no later than 60 days prior to the conclusion of an RMR Agreement.

(6) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to begin its Seasonal Operation Period if the first date of operation is prior to the date designated by the Resource Entity in its NSO. A Resource Entity with a Mothballed Generation Resource or Mothballed ESR that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the end date designated by the Resource Entity in its NSO if the Resource Entity intends to suspend operation later than that date. Notifications under this Section shall be provided by the Resource Entity by completing a Notification of Change of Resource Designation form (Section 22, Attachment H).

(7) Once the Resource Entity notifies ERCOT that a Mothballed Generation Resource or Mothballed ESR is operating under a Seasonal Operation Period, the Resource Entity does not need to annually notify ERCOT of such status.

(8) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to return the Mothballed Generation Resource or Mothballed ESR to year-round operation by completing a Notification of Change of Resource Designation form (Section 22, Attachment H).

(9) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR that is not currently mothballed indefinitely must notify ERCOT in writing, by completing an NSO (Section 22, Attachment E), no less than 150 days before the date on which the Mothballed Generation Resource or Mothballed ESR is to be suspended indefinitely or retired and decommissioned.

(10) ERCOT may request that a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period be available for operation earlier than June 1st or later than September 30th of any given calendar year. If ERCOT identifies a specific Resource Entity or QSE with which it will discuss such a request in an attempt to reach a mutually agreeable resolution, ERCOT shall issue a Notice as soon as practicable. The Notice shall include the Resource name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, and the potential duration of the extended operation period, including anticipated start and end dates. If agreement is reached for the Mothballed Generation Resource or Mothballed ESR to be available for operation earlier than June 1st or later than September 30th, the Resource Entity shall complete, within two Business Days, a Notification of Change of Resource Designation form (Section 22, Attachment H).

(11) If ERCOT and the Resource Entity or QSE cannot reach a mutual agreement to make the Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period available earlier than June 1st or later than September 30th of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority.

(12) ERCOT may evaluate, on an annual basis, Mothballed Generation Resources and Mothballed ESRs operating under a Seasonal Operation Period for RMR Service to address ERCOT System reliability during the portion of the year when the Mothballed Generation Resource or Mothballed ESR would be unavailable.

(13) A Resource Entity that submitted an NSO as a result of a Forced Outage must notify ERCOT of its intent to return to service as soon as practicable by updating its status in the Outage Scheduler and Current Operating Plan (COP) and is not required to submit a Notification of Change of Resource Designation.

(14) Before retiring and decommissioning either a Mothballed Generation Resource or Mothballed ESR is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

(15) If a Generation Resource or Mothballed ESR is designated as decommissioned and retired pursuant to any of the above provisions, ERCOT will permanently remove the Resource from the ERCOT registration systems in accordance with Section 3.10.1. Except as provided in paragraph (16) below, if a Resource Entity decides to bring a Decommissioned Generation Resource back to service at a later date, it will be considered a new Resource and must follow the Generator Interconnection or Modification (GIM) process detailed in the Planning Guide. If the Resource is designated as mothballed, ERCOT and TSPs will consider the Resource mothballed until the Resource Entity indicates a definitive return to service date pursuant to this Section.

(16) A Resource Entity may bring a Decommissioned Resource back to service without following the GIM process if the operating characteristics of the Resource are materially identical to the characteristics of the Resource as it existed prior to the date of decommissioning and the Resource Entity submits a Notification of Change of Resource Designation (Section 22, Attachment H) within three years of the date the Generation Resource was removed from the ERCOT Network Operations Model. The date of return proposed in the Notification must be a Network Operations Model load date that is no earlier than 45 days and no later than 180 days from the date of the Resource Entity’s Notification. ERCOT may delay the Network Operations Model load date based on the timing of the Resource Entity’s submission of complete Resource registration data. If the Resource Entity is not the Resource Entity that was associated with the Generation Resource at the time it was removed from the model, the Resource Entity shall provide ERCOT documentation that establishes the Resource Entity’s ownership of the Generation Resource.

(a) Notwithstanding the proposed date of return reflected in the Notification, as a condition for the synchronization of the Resource, ERCOT or the interconnecting Transmission and/or Distribution Service Provider (TDSP) may require any studies, testing, metering, or facility upgrades that ERCOT or the TDSP deem necessary for the reliable interconnection of the Resource, and ERCOT may require the Resource Entity to resolve any operational concern associated with the Resource. The TDSP may require the Resource Entity to compensate the TDSP for any required studies or upgrades in the same manner contemplated for new Generation Resources by the ERCOT Planning Guide, the TDSP’s tariff, and the Standard Generation Interconnection Agreement (SGIA).

(b) If ERCOT or the TDSP requires any studies, testing, metering or facility upgrades, or if ERCOT determines that operational concerns must be addressed, the Resource Entity must complete the commissioning process within 90 days of the date of synchronization, subject to any extension authorized by ERCOT for good cause.

(c) Any Resource that returns to service pursuant to this paragraph is entitled to any exemption from ERCOT requirements that the Resource was entitled to at the time it was removed from the model if the exemption still exists under ERCOT rules.

|  |
| --- |
| ***[NPRR885, NPRR995, and NPRR1007: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885 or NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]***  3.14.4 Must-Run Alternative Service  3.14.4.1 Overview and Description of MRAs  (1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.  (2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.  (a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.  (b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.  (c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT’s acceptance of an offer for a Demand Response MRA on ERCOT’s acceptance of an offer for a co-located Other Generation MRA offer.  (d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.  (3) An MRA may be connected at either transmission or distribution voltage.  (4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT’s RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.  (5) Each MRA must provide at least five MW of capacity.  (6) Eligible MRA resources may include:  (a) A proposed Generation Resource or Energy Storage Resource (ESR) that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.  (i) Proposed Generation Resources or ESRs must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generator Interconnection or Modification.  (ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource’s projected peak average capacity contribution during the MRA Contracted Hours.  (b) Proposed capacity additions to existing Generation Resources or ESRs, 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 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, ESR MRA, Other Generation MRA, or Demand Response MRA).  (12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.  (13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.  (14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.  (15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.  (16) QSEs must submit the following information for each MRA offer:  (a) The capacity, months and hours offered;  (b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;  (c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;  (d) The MRA Standby Price, represented in dollars per MW per hour;  (e) Required capital expenditure, if any, if the MRA offer is awarded;  (f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;  (g) The ramp period or startup time of the MRA or aggregated MRA;  (h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;  (i) The target availability of the MRA or aggregated MRA; and  (j) Any additional information required by ERCOT within the RFP.  (17) Demand Response MRAs shall not be deployed more than once per Operating Day.  (18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.  (19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource. |

|  |
| --- |
| ***[NPRR885: Insert Section 3.14.4.5 below upon system implementation:]***  **3.14.4.5 Standards for Generation Resource MRAs and ESR MRAs**  (1) A Generation Resource MRA and ESR MRA shall at all times communicate accurate Resource Status to ERCOT via telemetry as described in Section 6.4.6, Resource Status.  (2) A Generation Resource MRA and ESR MRA shall be committed by ERCOT VDI and Dispatched by SCED. |

|  |
| --- |
| ***[NPRR885: Insert Section 3.14.4.7 below upon system implementation:]***  **3.14.4.7 MRA Testing**  (1) ERCOT shall conduct a test of every MRA prior to the initial MRA Contracted Month.  (2) ERCOT may conduct an unannounced test of any MRA at any time during a MRA Contracted Month. Testing for MRAs, other than for Demand Response MRAs classified as providing Weather-Sensitive MRA, will be limited to no more than once per MRA Contracted Month. Testing for Demand Response MRAs classified as Weather-Sensitive MRA will be limited to no more than twice per MRA Contracted Month.  (3) ERCOT will not conduct an unannounced test of an MRA during a calendar month subsequent to an actual MRA deployment event.  (4) A substituted Demand Response MRA or Other Generation MRA will be subject to monthly unannounced testing regardless of tests or events occurring prior to the start date of the substitution.  (5) ERCOT shall limit the duration of MRA deployment periods of any single test to a maximum of one hour.  (6) For the purposes of Section 6.6.6.7, MRA Standby Payment, ERCOT may adjust the testing capacity results for a Generation Resource MRA or an ESR MRA to reflect conditions beyond the control of the Generation Resource MRA or ESR MRA. |

***3.17.1 Regulation Service***

(1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource or Energy Storage Resource (ESR) in discharge mode providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. Fast Responding Regulation Up Service (FRRS-Up) is a subset of Reg-Up Service in which the participating Resource provides Reg-Up capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal. The LFC signal for FRRS-Up is separate from the LFC signal for other Reg-Up.

|  |
| --- |
| ***[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource or Energy Storage Resource (ESR) in discharge mode providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal. |

(2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource or ESR in discharge mode providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. Fast Responding Regulation Down Service (FRRS-Down) is a subset of Reg-Down Service in which a participating Resource provides Reg-Down capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Down by an LFC signal. The LFC signal for FRRS-Down is separate from the LFC signal for other Reg-Down.

|  |
| --- |
| ***[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource or ESR in discharge mode providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. ERCOT dispatches Reg-Down by an LFC signal. |

***3.17.2 Responsive Reserve Service***

(1) Responsive Reserve (RRS) is a service used to restore or maintain the frequency of the ERCOT System in response to a significant frequency deviation.

(2) RRS is automatically self-deployed by Resources in a manner that results in real power increases or decreases.

(3) RRS may be provided by:

(a) On-Line Generation Resource capable of providing Primary Frequency Response with the capacity excluding Non-Frequency Responsive Capacity (NFRC);

(b) Resources capable of providing Fast Frequency Response (FFR) and sustaining their response for up to 15 minutes;

(c) Load Resources controlled by high-set under-frequency relays;

(d) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides; and

(e) ESRs.

***3.17.3 Non-Spinning Reserve Service***

(1) Non-Spinning Reserve (Non-Spin) is provided by using:

(a) Generation Resources, whether On-Line or Off-Line, capable of:

(i) Being synchronized and ramped to a specified output level within 30 minutes; and

(ii) Running at a specified output level for at least four consecutive hours;

(b) Controllable Load Resources qualified for Dispatch by Security-Constrained Economic Dispatch (SCED) and capable of:

(i) Ramping to an ERCOT-instructed consumption level within 30 minutes; and

(ii) Consuming at the ERCOT-instructed level for at least four consecutive hours;

(c) Load Resources that are not Controllable Load Resources and are qualified for deployment by the operator using the Ancillary Service Deployment Manager and capable of:

(i) Reducing consumption based on an ERCOT Extensible Markup Language (XML) instruction within 30 minutes; and

(ii) Maintaining that deployment until recalled; or

(d) ESRs.

(2) The Non-Spin may be deployed by ERCOT to increase available reserves in Real-Time Operations.

***3.17.4 ERCOT Contingency Reserve Service***

(1) ERCOT Contingency Reserve Service (ECRS) is a service that is provided using capacity that can be sustained at a specified level for two consecutive hours and is used to restore or maintain the frequency of the ERCOT System:

(a) In response to significant depletion of RRS;

(b) As backup Regulation Service; and

(c) By providing energy to avoid getting into or during an Energy Emergency Alert (EEA).

(2) ECRS may be provided through one or more of the following means:

(a) From On-Line or Off-Line Resources as prescribed in the Operating Guides following a significant frequency deviation in the ERCOT System; and

(b) Either manually or by using a four-second signal to provide energy on deployment by ERCOT.

(3) ECRS may be used to provide energy prior to or during the implementation of an EEA. ECRS provides Resource capacity, or capacity from interruptible Load available for deployment on ten minutes’ notice.

(4) ECRS may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Quick Start Generation Resources (QSGRs);

(c) Load Resources that may or may not be controlled by high-set, under-frequency relays;

(d) Controllable Load Resources;

(e) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides; and

(f) ESRs.

**3.18 Resource Limits in Providing Ancillary Service**

(1) For Generation Resources, Energy Storage Resources (ESRs), and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific designation of capacity to provide Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), and Non-Spinning Reserve (Non-Spin).

|  |
| --- |
| ***[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) For both Generation Resources and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific awards for Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), and Non-Spinning Reserve (Non-Spin). |

(2) For Non-Spin, the amount of Non-Spin provided must be less than or equal to the HSL for Off-Line Generation Resources.

|  |
| --- |
| ***[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) For Non-Spin, the amount of Non-Spin awarded must be less than or equal to the HSL for Off-Line Generation Resources. |

(3) For RRS:

(a) The full amount of RRS awarded to or self-arranged from an On-Line Generation Resource or ESR is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource and ESR subject to verified droop performance. The default value for any newly qualified Generation Resource or ESR shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;

(b) Generation Resources operating in the synchronous condenser fast-response mode may provide RRS up to the Generation Resource’s proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz. Once deployed, a Resource telemetering a Resource Status of ONRR shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled by ERCOT after frequency recovers above 59.98 Hz, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility;

(c) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and

(d) The amount of RRS provided from a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz. A Resource providing RRS as FFR that is deployed shall not recall its capacity until system frequency is greater than 59.98 Hz. Once deployed, a Resource telemetering a Resource Status of ONFFRRRS or ONFFRRRSL shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility. Once recalled, a Resource providing RRS as FFR must restore its full RRS Ancillary Service Resource Responsibility within 15 minutes after cessation of deployment or as otherwise directed by ERCOT.

|  |
| --- |
| ***[NPRR1007: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (3) For RRS:  (a) The full amount of RRS that can be provided by an On-Line Generation Resource or ESR is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource and ESR subject to verified droop performance. The default value for any newly qualified Generation Resource or ESR shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;  (b) Generation Resources operating in the synchronous condenser fast-response mode may be awarded RRS up to the Generation Resource’s proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz;  (c) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and  (d) The amount of RRS awarded to a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz. |

(4) For ECRS:

(a) The full amount of ECRS provided from an On-Line Generation Resource or ESR must be less than or equal to ten times the Emergency Ramp Rate;

(b) The full amount of ECRS provided by a Quick Start Generation Resource (QSGR) must be less than or equal to its proven ten-minute capability as demonstrated pursuant to paragraph (16) of Section 8.1.1.2, General Capacity Testing Requirements;

(c) Generation Resources operating in the synchronous condenser fast-response mode may provide ECRS up to the Generation Resource’s proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz; and

(d) For any Load Resources controlled by under-frequency relay and providing ECRS, the initiation setting of the automatic under-frequency relay setting shall not be lower than 59.70 Hz. To provide ECRS, Load Resources are not required to be controlled by under-frequency relays.

|  |
| --- |
| ***[NPRR1007: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (4) For ECRS:  (a) The full amount of ECRS that can be awarded to an On-Line Generation Resource must be less than or equal to ten times the Emergency Ramp Rate;  (b) The full amount of ECRS that can be awarded to a Quick Start Generation Resource (QSGR) must be less than or equal to its proven ten-minute capability as demonstrated pursuant to paragraph (16) of Section 8.1.1.2, General Capacity Testing Requirements;  (c) Generation Resources operating in the synchronous condenser fast-response mode may be awarded ECRS up to the Generation Resource’s proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz; and  (d) For any Load Resources controlled by under-frequency relay and awarded ECRS, the initiation setting of the automatic under-frequency relay setting shall not be lower than 59.70 Hz. To provide ECRS, Load Resources are not required to be controlled by under-frequency relays. |

**3.22.1.2 Generation Resource or Energy Storage Resource Interconnection Assessment**

(1) In the security screening study for a Generation Resource/Energy Storage Resource Interconnection or Change Request, ERCOT will perform a topology-check and determine if the Generation Resource or Energy Storage Resource (ESR) will become radial to a series capacitor(s) in the event of fewer than 14 concurrent transmission Outages.

(2) If ERCOT identifies that a Generation Resource or ESR will become radial to a series capacitor(s) in the event of fewer than 14 concurrent transmission Outages, the interconnecting TSP shall perform an SSR study including frequency scan assessment and/or detailed SSR assessment for the Interconnecting Entity (IE) in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria, to determine SSR vulnerability. The SSR study shall determine which system configurations create vulnerability to SSR. Alternatively, if the IE can demonstrate to ERCOT’s and the interconnecting TSP’s satisfaction that the Generation Resource or ESR is not vulnerable to SSR, then the interconnecting TSP is not required to perform the SSR study. If an SSR study is conducted, the interconnecting TSP shall submit it to ERCOT upon completion and shall include any SSR Mitigation plan developed by the IE that has been reviewed by the TSP.

(3) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of six or fewer concurrent transmission Outages, the IE shall develop an SSR Mitigation plan, provide it to the interconnecting TSP for review and inclusion in the TSP’s SSR study report to be approved by ERCOT, and implement the SSR Mitigation prior to Initial Synchronization.

(a) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of four concurrent transmission Outages, the IE may install SSR Protection in lieu of SSR Mitigation, as required by paragraph (3) above, if:

(i) The Generation Resource or ESR satisfied Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, between August 12, 2013 and March 20, 2015;

(ii) The SSR Protection is approved by ERCOT; and

(iii) The Generation Resource or ESR installs the ERCOT-approved SSR Protection prior to Initial Synchronization.

(b) For any Generation Resource or ESR that satisfied Planning Guide Section 6.9 before September 1, 2020, if the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, the IE may elect not to develop or implement an SSR Mitigation plan, in which case ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring. The IE shall provide ERCOT written Notice of any such election before the Generation Resource or ESR achieves Initial Synchronization, and the Generation Resource or ESR shall not be permitted to proceed to Initial Synchronization until ERCOT has implemented SSR monitoring.

(4) ERCOT shall respond with its comments or approval of an SSR study report, which should include any required SSR Mitigation plan, within 30 days of receipt. ERCOT comments should be addressed as soon as practicable by the TSP, and any action taken in response to ERCOT’s comments on an SSR study report shall be subject to further ERCOT review and approval. Upon approval of the SSR study report, ERCOT shall notify the interconnecting TSP, and the interconnecting TSP shall provide the approved SSR study report to the IE.

**3.22.1.3 Transmission Project Assessment**

(1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSR vulnerability assessment, including a topology-check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. The TSP shall include a summary of the results of this assessment in the project submission to the Regional Planning Group (RPG) pursuant to Section 3.11.4, Regional Planning Group Project Review Process. For Tier 4 projects that include Transmission Facilities connecting to or operating at 345 kV, the TSP shall provide the SSR assessment for ERCOT’s review. For the purposes of this Section, a Generation Resource or ESR is considered an existing Generation Resource or ESR if it satisfies Planning Guide Section 6.9 at the time the Transmission Facilities are proposed.

(2) If while performing the independent review of a transmission project, ERCOT determines that the transmission project may cause an existing Generation Resource or ESR or a Generation Resource or ESR satisfying Planning Guide Section 6.9 at the time the transmission project is proposed to become vulnerable to SSR, ERCOT shall perform an SSR vulnerability assessment, including topology-check and frequency scan in accordance with Section 3.22.2 if such an assessment was not included in the project submission. ERCOT shall include a summary of the results of this assessment in the independent review.

(3) If the frequency scan assessment in paragraphs (1) or (2) above indicates potential SSR vulnerability in accordance with Section 3.22.2, the TSP(s) that owns the affected series capacitor(s), in coordination with the TSP proposing the Transmission Facilities, shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(4) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource or ESR if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(5) If the SSR study confirms a Generation Resource or ESR is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and implement SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(6) If the SSR study confirms a Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(7) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

**3.22.1.4 Annual SSR Review**

(1) ERCOT shall perform an SSR review annually. The annual review shall include the following elements:

(a) The annual review shall include a topology-check applying the system network topology that is consistent with a year 3 Steady State Working Group (SSWG) base case developed in accordance with Planning Guide Section 6.1, Steady-State Model Development. ERCOT shall post the SSR annual topology-check report to the Market Information System (MIS) Secure Area by May 31 of each year.

(b) If ERCOT identifies that a Generation Resource or ESR will become radial to series capacitors(s) in the event of less than 14 concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. ERCOT shall prepare a report to summarize the results of the frequency scan assessment and provide it to the Resource Entity and the affected TSP.

(i) If the frequency scan assessment described in paragraph (b) above shows the Generation Resource or ESR has potential SSR vulnerability in the event of six or fewer concurrent transmission Outages, the TSP(s) that owns the affected series capacitor compensated Transmission Element in coordination with the interconnecting TSP shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(ii) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource or ESR if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(iii) If the SSR study confirms the Generation Resource or ESR is vulnerable to SSR in the event of four or less concurrent transmission Outages, the TSP that owns the affected series capacitor compensated Transmission Element shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and install SSR Mitigation on the ERCOT transmission system. The SSR Mitigation shall be developed, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(iv) If the SSR study confirms the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(v) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline.

***3.22.2 Subsynchronous Resonance Vulnerability Assessment Criteria***

(1) A Generation Resource or ESR is considered to be potentially vulnerable to SSR in the topology-check if the Generation Resource or ESR will become radial to a series capacitors(s) in the event of less than 14 concurrent transmission Outages. A frequency scan assessment and/or a detailed SSR assessment shall be required to screen for system conditions causing potential SSR vulnerability.

(2) In determining whether a Generation Resource or ESR is considered to be potentially vulnerable to SSR in the frequency scan assessment results, the following criteria shall be considered:

(a) Induction Generator Effect (IGE) and Subsynchronous Control Interaction (SSCI):

(i) When considering the total impedance of the generator and the applicable part of the ERCOT System, if the total resistance is negative at a reactance crossover of zero Ohms from negative to positive with increasing frequency, then the generator is considered to be potentially vulnerable to IGE/SSCI;

(b) Torsional Interaction:

(i) If the sum of the electrical damping (De) plus the mechanical damping (Dm) results in a negative value then the generator is potentially vulnerable to Torsional Interaction. Dm at +/- 1 Hz of the modal frequency may be utilized to compare to De; and

(c) Torque Amplification:

(i) When considering the total impedance of the generator and the ERCOT system, if a 5% or greater reactance dip, or a reactance crossover of zero Ohms from negative to positive with increasing frequency, occurs within a +/- 3 Hz complement of the modal frequency, then the generator is considered to be potentially vulnerable to Torque Amplification. The percentage of a reactance dip is on the basis of the reactance maximum at the first inflection point of the dip where the reactance begins to decrease with increasing frequency.

(3) The detailed SSR assessment shall include an electromagnetic transient program analysis or similar analysis. A Generation Resource or ESR is considered to be vulnerable to SSR if any of the following criteria are met:

(a) The SSR vulnerability results in more than 50% of fatigue life expenditure over the expected lifetime of the unit;

(i) If the fatigue life expenditure is not available, the highest torsional torque caused by SSR is more than 110% of the torque experienced during a transmission fault with the series capacitors bypassed;

(b) The oscillation, if occurred, is not damped; or

(c) The oscillation, if occurred, results in disconnection of any transmission and generation facilities.

***3.22.3 Subsynchronous Resonance Monitoring***

(1) For purposes of SSR monitoring, a common tower Outage loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater is considered as one contingency.

(2) ERCOT’s responsibilities for SSR monitoring shall consist of the following activities if a Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages identified in the SSR vulnerability assessment and does not implement SSR Mitigation:

(a) ERCOT shall identify the combinations of Outages of Transmission Elements that may result in SSR vulnerability and provide these Transmission Elements to the affected Resource Entity and its interconnected TSP;

(b) ERCOT shall monitor the status of these Transmission Elements identified in paragraph (a) above;

(c) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being three contingencies away from SSR vulnerability, ERCOT will identify options for mitigation that would be implemented if an additional transmission Outage were to occur, including communications with TSPs to determine potential Outage cancellations and time estimates to reinstate Transmission Facilities;

(d) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being two contingencies away from SSR vulnerability, ERCOT shall take action to mitigate SSR vulnerability to the affected Generation Resource or ESR. ERCOT shall consider the actions in the following order unless reliability considerations dictate a different order. Actions that may be considered are:

(i) No action if the affected Generation Resource or ESR is equipped with SSR Protection and has elected for ERCOT to forego action to mitigate SSR vulnerability;

(ii) Coordinate with TSPs to withdraw or restore an Outage within eight hours if feasible;

(iii) If the actions described in (i) and (ii) above are not feasible, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitors(s); or

(iv) Other actions specific to the situation, including, but not limited to, Verbal Dispatch Instruction (VDI) to the Resource’s Qualified Scheduling Entity (QSE).

(e) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being one contingency away from SSR vulnerability, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitor(s).

(f) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being two or less contingencies away from SSR vulnerability, ERCOT shall notify the QSE representing the affected Generation Resource or ESR by voice communication as soon as practicable that the SSR vulnerability scenario has occurred; initiate the mitigation actions described in paragraphs (2)(d)(i) through (iv) above; and provide additional notifications to the QSE of each relevant topology change until the affected Generation Resource(s) or ESR(s) are at least three contingencies away from SSR vulnerability.

4.4.6.3 PTP Obligations with Links to an Option DAM Award Eligibility

(1) A bid for a PTP Obligation with Links to an Option will not be considered eligible for award for an Operating Hour if it sources at a Resource Node where a Generation Resource or Energy Storage Resource (ESR) has a COP Resource Status of:

(a) OUT for an Operating Hour; or

(b) OFF for an Operating Hour; and

(i) The QSE representing the Resource has not submitted a valid Three-Part Supply Offer or Ancillary Service Offer to be considered by the DAM; and

(ii) The QSE representing the Resource has not submitted a valid Energy Only Offer at any Resource Node associated with the Resource.

(2) Where more than one Generation Resource or ESR is associated with a Resource Node, ERCOT will consider a PTP Obligation with Links to an Option bid eligible for award unless all Generation Resources and ESRs associated with the Resource Node do not satisfy the COP Resource Status requirements in paragraph (1) above during the Operating Hour.

(3) In order for ERCOT to award a bid for a PTP Obligation with Links to an Option under this section for an upcoming year, by October 1 of the prior year a NOIE must have provided ERCOT with an attestation that the Generation Resource or ESR for the Resource Node where the bid is sourced is owned or controlled by the NOIE, or has a contractual commitment for capacity and/or energy with the NOIE. The attestation must be executed by an officer or executive with authority to bind the NOIE, and submitted to ERCOT. ERCOT shall rely exclusively on the attestation provided by a NOIE in determining eligibility for bid awards under this section. ERCOT shall issue a Market Notice by September 1 of each year reminding NOIEs of the October 1 deadline for submitting attestations for the upcoming year.

**4.4.7.1 Self-Arranged Ancillary Service Quantities**

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the Ancillary Service Obligation allocated to it by ERCOT. QSEs may not self-arrange Regulation Service amounts that include Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) quantities. In addition, a QSE may self-arrange up to 100 MW of ERCOT Contingency Reserve Service (ECRS), 100 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 50 MW of Non-Spinning Reserve (Non-Spin) in excess of its corresponding Ancillary Service Obligation, provided that the amount self-arranged from the QSE’s Resources for a given Ancillary Service shall not exceed the amount of the QSE’s Ancillary Services Obligation for that Ancillary Service. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation. Any Self-Arranged Ancillary Service Quantities in excess of a QSE’s Ancillary Service Obligation will be considered to be offered in the DAM or Supplemental Ancillary Services Market (SASM), as applicable, for $0/MWh.

|  |
| --- |
| ***[NPRR1091: Replace paragraph (1) above with the following upon system implementation:]***  (1) For each Ancillary Service, a QSE may self-arrange all or a portion of the Ancillary Service Obligation allocated to it by ERCOT. QSEs may not self-arrange Regulation Service amounts that include Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) quantities. In addition, a QSE may self-arrange up to 150 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 300 MW of Non-Spinning Reserve (Non-Spin) in excess of its corresponding Ancillary Service Obligation, provided that the amount self-arranged from the QSE’s Resources for a given Ancillary Service shall not exceed the amount of the QSE’s Ancillary Services Obligation for that Ancillary Service. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation. Any Self-Arranged Ancillary Service Quantities in excess of a QSE’s Ancillary Service Obligation will be considered to be offered in the DAM or Supplemental Ancillary Services Market (SASM), as applicable, for $0/MWh. |

|  |
| --- |
| ***[NPRR1008: Replace paragraph (1) above with the following upon system implementation or upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) For each Ancillary Service, a QSE may self-arrange all or a portion of the advisory Ancillary Service Obligation allocated to it by ERCOT, subject to the QSE’s share of system-wide limits as established by Section 3.16, Standards for Determining Ancillary Service Quantities. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its final Ancillary Service Obligation; ERCOT shall pay the QSE the respective Day-Ahead Ancillary Service price for any Self-Arranged Ancillary Service Quantities that exceed a QSE’s final Ancillary Service Obligation. |

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, needs to be obtained through the DAM.

|  |
| --- |
| ***[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, remains to be obtained based on DAM offers and associated Ancillary Service Demand Curves (ASDCs). |

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities unless ERCOT opens a SASM.

|  |
| --- |
| ***[NPRR1008: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities. |

(4) Before 1430 in the Day-Ahead, all Self-Arranged Ancillary Service Quantities must be represented by physical capacity, either by Generation Resources, ESRs, or Load Resources, or backed by Ancillary Service Trades.

(5) The QSE may self-arrange Reg-Up, Reg-Down, ECRS, RRS, and Non-Spin.

(6) The QSE may self-arrange Ancillary Services from one or more Resources it represents and/or through an Ancillary Service Trade.

(7) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a SASM notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than 100 MW of ECRS, 100 MW of RRS, 25 MW of Reg-Up, 25 MW of Reg-Down, and 50 MW of Non-Spin greater than the additional Ancillary Service amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT.

(8) If a QSE does not self-arrange all of its Ancillary Service Obligation, ERCOT shall procure the remaining amount of that QSE’s Ancillary Service Obligation.

|  |
| --- |
| ***[NPRR1008: Replace paragraphs (7) and (8) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]***  (7) A QSE shall not submit Ancillary Services trades that result in the QSE’s purchased quantities of Ancillary Services exceeding the QSE’s Self-Arranged Ancillary Service Quantities.  (a) At 1430 in the Day-Ahead, ERCOT shall post a report on the MIS Certified Area to notify the QSE if there is an overage in the QSE’s purchased quantities of Ancillary Services in violation of the above limitation.  (b) If the QSE has such an overage as of the end of the Adjustment Period, that QSE will be charged for any quantity that exceeds their Self-Arranged Ancillary Service Quantities per Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge. |

(9) For self-arranged RRS, the QSE shall indicate the quantity of the service that is provided from:

(a) Resources providing Primary Frequency Response;

(b) Load Resources controlled by high-set under-frequency relays; and

(c) Fast Frequency Response (FFR) Resources.

(10) For self-arranged ECRS, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched and those that are SCED-dispatchable.

|  |
| --- |
| ***[NPRR1213: Replace paragraph (10) above with the following upon system implementation, and upon system implementation of NPRR1171:]***  (10) For self-arranged ECRS and Non-Spin, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) on circuits subject to Load shed, and Resources that are SCED-dispatchable not on circuits subject to Load shed.  (11) For self-arranged Non-Spin, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched, DGRs and DESRs on circuits subject to Load shed, and Resources that are SCED-dispatchable and not on circuits subject to Load shed. |

4.4.7.3 Ancillary Service Trades

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

|  |
| --- |
| ***[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity or purchase Ancillary Services in the Real-Time Market (RTM) between a buyer and a seller. |

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

|  |
| --- |
| ***[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted. |

(3) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Ancillary Service Trades that are invalid Ancillary Service Trades. The QSE may correct and resubmit any invalid Ancillary Service Trade, but the reporting time of the trade is determined by when the validated Ancillary Service Trade was submitted and not when the original invalid Ancillary Service Trade was submitted.

(4) A QSE with an Ancillary Service Supply Responsibility for ECRS, originally designated to be provided by a Generation Resource, may transfer its responsibility via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by a Generation Resource.

|  |
| --- |
| ***[NPRR1008: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (4) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a SCED-dispatchable Resource, may transfer that portion of its Ancillary Service Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by a SCED-dispatchable Resource. |

|  |
| --- |
| ***[NPRR1213: Delete paragraph (4) above upon system implementation, and upon system implementation of NPRR1171, and renumber accordingly.]*** |

(5) A QSE with an Ancillary Service Supply Responsibility for ECRS, originally designated to be provided by a Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz, may transfer its responsibility via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by either:

|  |
| --- |
| ***[NPRR1008: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (5) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz, may transfer that portion of its Ancillary Service Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by either: |

(a) A Generation Resource;

(b) An ESR; or

(c) A Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz.

|  |
| --- |
| ***[NPRR1213: Delete paragraph (5) above upon system implementation, and upon system implementation of NPRR1171, and renumber accordingly.]*** |

(6) The table below shows the ECRS trades that are allowed for each type of original responsibility:

|  |  |  |
| --- | --- | --- |
|  | **Allowable ECRS Ancillary Service Trades** | |
| **Original Responsibility** | **SCED-dispatchable ECRS** | **Manually dispatched ECRS** |
| SCED-dispatchable ECRS | Yes | No |
| Manually dispatched ECRS | Yes | Yes |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1213: Replace paragraph (6) above with the following upon system implementation, and upon system implementation of NPRR1171:]***  (4) The table below shows the ECRS trades that are allowed for each type of original responsibility:   |  |  |  |  | | --- | --- | --- | --- | |  |  |  |  | |  | **Allowable ECRS Ancillary Service Trades** | | | | **Original Responsibility** | **SCED-dispatchable ECRS not from DGRs and DESRs on a Load shed circuit** | **SCED-dispatchable ECRS from DGRs and DESRs on a Load shed circuit** | **Manually dispatched ECRS** | | SCED-dispatchable ECRS not from DGRs and DESRson a Load shed circuit | Yes | No | No | | SCED-dispatchable ECRS from DGRs and DESRson a Load shed circuit | Yes | Yes | No | | Manually dispatched ECRS | Yes | No | Yes | |

(7) The table below shows the RRS trades that are allowed for each type of original responsibility:

|  |  |  |  |
| --- | --- | --- | --- |
|  | **Allowable RRS Ancillary Service Trades** | | |
| **Original Responsibility** | **Resource providing Primary Frequency Response** | **Resource providing FFR triggered at 59.85 Hz** | **Load Resource triggered at 59.7 Hz** |
| Resource providing Primary Frequency Response | Yes | No | No |
| Resource providing FFR triggered at 59.85 Hz | Yes | Yes | Yes |
| Load Resource triggered at 59.7 Hz | Yes | No | Yes |

(8) The table below shows the Non-Spin trades that are allowed for each type of original responsibility:

|  |  |  |
| --- | --- | --- |
|  | **Allowable Non-Spin Ancillary Service Trades** | |
| **Original Responsibility** | **Generation Resource or Controllable Load Resource** | **Load Resource other than a Controllable Load Resource** |
| Generation Resource or Controllable Load Resource | Yes | No |
| Load Resource other than a Controllable Load Resource | Yes | Yes |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1213: Replace paragraph (8) above with the following upon system implementation, and upon system implementation of NPRR1171:]***  (6) The table below shows the Non-Spin trades that are allowed for each type of original responsibility:   |  |  |  |  | | --- | --- | --- | --- | |  |  |  |  | |  | **Allowable Non-Spin Ancillary Service Trades** | | | | **Original Responsibility** | **Generation Resource not DGRs and DESRs on a Load shed circuit or Controllable Load Resource** | **DGRs and DESRs on a Load shed circuit** | **Load Resource other than a Controllable Load Resource** | | Generation Resource not on circuits subject to Load shed or Controllable Load Resource | Yes | No | No | | DGRs and DESRs on a Load shed circuit | Yes | Yes | No | | Load Resource other than a Controllable Load Resource | Yes | No | Yes | |

(9) A QSE with an Ancillary Service Supply Responsibility for Regulation Service may transfer that portion of its Ancillary Service Supply Responsibility via Ancillary Service Trade(s) to another QSE only if that QSE provides the transferred portion with Regulation Service that is not Fast Responding Regulation Service (FRRS). The table below shows the Regulation Service trades that are allowed for each type of original responsibility. The same limitations apply separately to both Reg-Up and Reg-Down:

|  |  |  |
| --- | --- | --- |
|  | **Allowable Regulation Ancillary Service Trades** | |
| **Original Responsibility** | **Regulation Service that is not FRRS** | **FRRS** |
| Regulation Service that is not FRRS | Yes | No |
| FRRS | Yes | No |

4.4.9.3.3 Energy Offer Curve Cost Caps

(1) The following Energy Offer Curve Cost Caps must be used for the purpose of make-whole Settlements, Real-Time High Dispatch Limit Override Energy Payments, and Voltage Support Service Payments:

(a) Nuclear = $15.00/MWh;

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

(c) Combined Cycle greater than 90 MW = 9 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(d) Combined Cycle less than or equal to 90 MW = 10 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(e) Gas - Steam Supercritical Boiler = 10.5 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(f) Gas Steam Reheat Boiler = 11.5 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(g) Gas Steam Non-reheat or boiler without air-preheater = 14.5 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(h) Simple Cycle greater than 90 MW = 14 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(i) Simple Cycle less than or equal to 90 MW = 15 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(j) Reciprocating Engines = 16 MMBtu/MWh \* ((Percentage of FIP \* FIP) + (Percentage of FOP \* FOP))/100, as specified in the Energy Offer Curve;

(k) Hydro = $10.00/MWh;

(l) Other = SWCAP;

|  |
| --- |
| ***[NPRR1008: Replace item (l) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (l) Other = DASWCAP or RTSWCAP; |

(m) RMR Resource = SWCAP;

|  |
| --- |
| ***[NPRR1008: Replace item (m) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (m) RMR Resource = effective Value of Lost Load (VOLL); |

(n) Wind Generation Resources = $0.00/MWh;

(o) PhotoVoltaic Generation Resource (PVGR) = $0.00/MWh; and

(p) Energy Storage Resource (ESR) = $0.00/MWh.

(2) ERCOT shall produce an annual report each April that provides the amount of DAM and RUC Make-Whole Payments during the previous calendar year for Resources categorized as Other, per item (1)(l) above, as a percentage of the total amount of DAM and RUC Make-Whole Payments made during the previous calendar year. The report shall be based on final Settlements and include the total number of Resources classified as Other. ERCOT shall present this report annually to the appropriate Technical Advisory Committee (TAC) subcommittee. If there are no Make-Whole Payments for Resources categorized as Other for a given calendar year, then ERCOT will not be required to produce the annual report.

(3) Items in paragraphs (1)(c) and (d) above are determined by capacity of largest simple-cycle combustion turbine in the train selected.

(4) The FIP and FOP used to calculate the Energy Offer Curve Cap for Make-Whole Payment calculation purposes shall be the FIP or FOP for the Operating Day. In the event the Energy Offer Curve Cap for Make-Whole Payment calculation purposes must be calculated before the FIP or FOP is available for the particular Operating Day, the FIP and FOP for the most recent preceding Operating Day shall be used. Once the FIP and FOP are available for a particular Operating Day, those values shall be used in the calculations. If the percentage fuel mix is not specified or if no Energy Offer Curve exists, then the minimum of FIP or FOP shall be used.

|  |
| --- |
| ***[NPRR1216: Insert paragraph (5) below upon system implementation:]***  (5) During an Emergency Offer Cap (ECAP) Effective Period, the SWCAP used for purposes of calculating the Energy Offer Curve Cost Caps shall be set to the maximum value of SWCAP that was effective for the Operating Day. |

|  |
| --- |
| ***[NPRR1216: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (5) During an ECAP Effective Period, for purposes of calculating the Energy Offer Curve Cost Caps, the DASWCAP shall be set to the DASWCAP that was used to clear the DAM, and the VOLL shall be set to the maximum value VOLL that was effective for the Operating Day. |

**6.5.1.1 ERCOT Control Area Authority**

(1) ERCOT, as Control Area Operator (CAO), is authorized to perform the following actions for the limited purpose of securely operating the ERCOT Transmission Grid under the standards specified in North American Electric Reliability Corporation (NERC) Standards, the Operating Guides and these Protocols,including:

(a) Direct the physical operation of the ERCOT Transmission Grid, including circuit breakers, switches, voltage control equipment, and Load-shedding equipment;

(b) Dispatch Resources that have committed to provide Ancillary Services;

|  |
| --- |
| ***[NPRR1010: Replace paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (b) Dispatch Resources that have been awarded Ancillary Services; |

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

(d) Direct the implementation of Reliability Must-Run (RMR) Service, Remedial Action Plans (RAPs), Automatic Mitigation Plans (AMPs), Remedial Action Schemes (RASs), and transmission switching to prevent the violation of ERCOT Transmission Grid security limits; and

|  |
| --- |
| [NPRR1198: Replace paragraph (d) above with the following upon system implementation and renumber accordingly:]  (d) Direct the implementation of Reliability Must-Run (RMR) Service;  (e) Direct the implementation, disabling, or reversal of implementation of Remedial Action Plans (RAPs), Automatic Mitigation Plans (AMPs), Remedial Action Schemes (RASs), Pre-Contingency Action Plans (PCAPs), Extended Action Plans (EAPs), and transmission switching to prevent the violation of ERCOT Transmission Grid security limits; and |

(e) Perform additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT Transmission Grid to a secure state in the event of an ERCOT Transmission Grid Emergency Condition.

(2) Unless the ERCOT Protocols or Other Binding Documents explicitly provide otherwise, ERCOT shall not model, monitor, direct operation of, or otherwise exercise any operational authority over any facility that operates on the low voltage side of the distribution transformer except as may be necessary for the following purposes:

(a) To ensure the reliable interconnection, dispatch, operation, and Settlement of any Generation Resource, Energy Storage Resource (ESR), Load Resource, or Emergency Response Service (ERS) Resource that is, or is proposed to be, interconnected at distribution voltage, and to ensure the reliable operation and Settlement of any other ERCOT-registered generator;

(b) To provide ERCOT information about all generators interconnected at distribution voltage as requested by ERCOT pursuant to these Protocols or Other Binding Documents for the purposes of ensuring accurate Settlement and operating and planning the Transmission Grid; and

(c) To effectuate automatic or manual Load-shedding as prescribed by these Protocols or Other Binding Documents.

(3) Nothing in paragraph (2) above limits ERCOT’s authority to require that a Transmission Service Provider (TSP) or Transmission Operator (TO) disconnect any Facility operated at distribution voltage from the ERCOT System if ERCOT determines such action is necessary to address a reliability concern on the ERCOT Transmission Grid. Additionally, nothing in paragraph (2) above limits ERCOT’s authority to require appropriate modeling and telemetry of transmission Loads that may represent multiple distribution-level Loads, as provided in Section 3.10.7.2, Modeling of Resources and Transmission Loads.

(4) Consistent with paragraph (1)(e) above, if ERCOT seeks to exercise its authority to prevent an anticipated Emergency Condition relating to serving Load in the current or next Season by procuring existing capacity that may be used to maintain ERCOT System reliability in a manner not otherwise delineated in these Protocols and the Operating Guides, ERCOT shall take the following actions:

(a) Upon determination by ERCOT that additional capacity is needed to prevent an Emergency Condition and prior to any procurement activity associated with such additional capacity, ERCOT shall issue a Notice as soon as practicable with the following information:

(i) A detailed description of the reliability condition and need for additional capacity as determined by ERCOT and the timing of the proposed procurement;

(ii) Justification for the quantity of additional capacity to be requested;

(iii) Identification of potential Generation Resources, Energy Storage Resources (ESRs), or Load providing capacity considered by ERCOT to be acceptable for providing the additional capacity. Load capacity may be provided by Entities who, at ERCOT’s direction, would interrupt consumption of electric power and remain interrupted until released by ERCOT; and

(iv) A schedule of activities associated with the proposed procurement.

(b) If ERCOT identifies a specific Entity with which it will negotiate the terms for procurement of additional capacity, then ERCOT shall issue a Notice as soon as practicable that includes the Entity name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, the name of the Resource Entity, and the potential duration of any contract, including anticipated start and end dates.

(c) ERCOT shall, to the fullest extent practicable, ensure that any actions taken to procure additional capacity meet the following criteria:

(i) Any capacity procured pursuant to this paragraph will be procured using an open process, and the terms of the procurement between ERCOT and the Entity will be memorialized in contracts that will be publicly available for inspection on the ERCOT website.

(ii) Each contract will include specified financial terms and termination dates. For purposes of Settlement, any contract associated with a Generation Resource or ESR will include substantially the same terms and conditions as an RMR Unit under a RMR Agreement, including the Eligible Cost budgeting process.

(iii) ERCOT shall provide notice to the ERCOT Board, at the next ERCOT Board meeting after ERCOT has signed the contract, that the actions required prior to execution of the contract, pursuant to paragraphs (4)(a) through (c) above, were completed by ERCOT before the contract was executed.

(iv) Any information submitted by the Entity to ERCOT through the procurement process may be designated as Protected Information and treated in accordance with the provisions of Section 1.3, Confidentiality, provided that final contract terms must be made available for public inspection.

(d) A Generation Resource or ESR that has received capital contributions from ERCOT pursuant to a contract executed under this paragraph (4) may not participate in the energy or Ancillary Services markets until such capital contributions have been refunded to ERCOT. For the purposes of this Section, capital contributions are defined as improvements with an asset life greater than one year under the applicable federal tax rules. The Resource Entity’s refund of capital contributions shall be a lump sum payment calculated as follows:

(i) If the Generation Resource or ESR chooses to participate in the energy or Ancillary Service markets after the termination date of the contract executed under this paragraph (4), the Qualified Scheduling Entity (QSE) representing the Resource Entity shall repay, in a lump sum payment, 100% of the book value of the capitalized equipment and all installation charges leading to turn key, one-time startup based on a linear depreciation over the estimated life of the capitalized component(s) in accordance with Generally Accepted Accounting Principles (GAAP) standards for electric utility equipment. The estimated life shall be based on documentation provided by the manufacturer; if installing used equipment, the estimated life may be based on an approximation agreed to by the Resource Entity and ERCOT.

(ii) If the Generation Resource or ESR chooses to participate in the energy or Ancillary Services markets as contemplated in item (4)(d)(i) above, and its participation requires a lump sum payment of capital contributions, ERCOT will issue a notice to all registered Market Participants announcing the Generation Resource’s or ESR’s decision to participate in the market(s) and identifying the amount of the lump sum payment due pursuant to item (4)(d)(i) above. ERCOT will also issue a notice to all registered Market Participants after completion of the collection and disbursement of the capital contributions, as described in item (4)(d)(iii) below, and after resolution of any disputes related to these capital contributions.

(iii) After ERCOT receives a Notification of Change of Resource Designation (Section 22, Attachment H, Notification of Change of Resource Designation) changing the Resource designation to “operational” at a future date, ERCOT shall charge the QSE representing the Resource Entity for capital expenditures incurred and previously paid to the Resource Entity as a result of the Resource’s return to service pursuant to this Section.

(A) For months in the contract term where notice is received more than five Business Days prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any payments made for the capital expenditure associated with that month and subsequent months of the term, on the next practical Settlement but no later than the True-Up Settlement.

(B) For months in the contract term where notice is received five Business Days or less prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any payments made for the capital expenditures within 45 days of receipt of the notice.

(C) ERCOT shall distribute the repayment to QSEs representing Load on the same basis used to collect the monthly capital expenditures, using a monthly Load Ratio Share (LRS). A QSE’s monthly LRS shall be the QSE’s total Real-Time Adjusted Metered Load (AML) for the month divided by the total ERCOT Real-Time AML for the same month.

(e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the System-Wide Offer Cap (SWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion.

|  |
| --- |
| ***[NPRR1010: Replace paragraph (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the Real-Time System-Wide Offer Cap (RTSWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion. |

(f) An Entity cannot be compelled to enter into a contract under this paragraph.

***6.5.3 Equipment Operating Ratings and Limits***

(1) ERCOT shall consider all equipment operating limits when issuing Dispatch Instructions. Except as stated in Section 6.5.9, Emergency Operations, if a Dispatch Instruction conflicts with a restriction that may be placed on equipment from time to time by a TSP, a DSP, or a QSE representing a Generation Resource or ESR to protect the integrity of equipment, ERCOT shall honor the restriction.

|  |
| --- |
| ***[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (1) ERCOT shall consider all equipment operating limits when issuing Dispatch Instructions. Except as stated in Section 6.5.9, Emergency Operations, if a Dispatch Instruction conflicts with a restriction that may be placed on equipment from time to time by a TSP, a DSP, a DCTO, or a QSE representing a Generation Resource or ESR to protect the integrity of equipment, ERCOT shall honor the restriction. |

(2) Each TSP shall notify ERCOT of any limitations on the TSP’s system that may affect ERCOT Dispatch Instructions. ERCOT shall continuously maintain a posting on the MIS Secure Area of any TSP limitations that may affect Dispatch Instructions. Examples of such limitations may include: temporary changes to transmission or transformer ratings, temporary changes to range of automatic tap position capabilities on auto-transformers, fixing or blocking tap changer, changes to no-load tap positions or other limitations affecting the delivery of energy across the ERCOT Transmission Grid. Any conflicts that cannot be satisfactorily resolved may be brought to ERCOT by any of the affected Entities for investigation and resolution.

|  |
| --- |
| ***[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (2) Each TSP or DCTO shall notify ERCOT of any limitations on the TSP’s or DCTO’s system that may affect ERCOT Dispatch Instructions. ERCOT shall continuously maintain a posting on the MIS Secure Area of any TSP or DCTO limitations that may affect Dispatch Instructions. Examples of such limitations may include: temporary changes to transmission or transformer ratings, temporary changes to range of automatic tap position capabilities on auto-transformers, fixing or blocking tap changer, changes to no-load tap positions or other limitations affecting the delivery of energy across the ERCOT Transmission Grid. Any conflicts that cannot be satisfactorily resolved may be brought to ERCOT by any of the affected Entities for investigation and resolution. |

**6.5.5.1 Changes in Resource Status**

(1) Each QSE shall notify ERCOT via telemetry of a change in Resource Status that is not related to a Forced Outage as soon as practicable but no longer than 15 minutes after the change in status occurs and through changes in the Current Operating Plan (COP) as soon as practicable but no longer than 60 minutes after the change in status of the Resource occurs.

(2) When an On-Line Resource is experiencing an event that may affect its availability and/or capability and that requires further actions to stabilize the Resource and/or determine the impact of the event, the QSE may change the Resource Status to ONHOLD within 15 minutes of experiencing an event. Following this Resource Status change, the telemetered HSL and any other applicable telemetry of the Resource as specified in paragraph (2) of Section 6.5.5.2, Operational Data Requirements, shall be updated as soon as practicable but no longer than 15 minutes after the change in Resource Status to ONHOLD. After the QSE has determined the impact of the event, the QSE shall change the Resource Status to its updated status as soon as practicable but no longer than 60 consecutive minutes of being in the ONHOLD status.

(3) Each QSE shall promptly inform ERCOT when the operating mode of the Automatic Voltage Regulator (AVR) or Power System Stabilizer (PSS) for the QSE’s Generation Resource or ESR is changed while the Resource is On-Line. The QSE shall also provide the Resource’s AVR or PSS status logs to ERCOT upon request. For each Generation Resource that is On-Line but not producing real power and is not capable of providing Reactive Power, each QSE must still telemeter its AVR status to ERCOT but is not required to provide verbal notifications of its AVR status changes to ERCOT during these operating conditions.

(4) Each QSE shall immediately report to ERCOT and the TSP any inability of the QSE’s Generation Resource or ESR required to meet its reactive capability requirements in these Protocols.

(5) Each QSE shall timely update the telemetered Resource Status unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating the telemetered Resource Status only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the telemetered Resource Status begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

(6) A QSE or Resource Entity may use a Generation Resource or ESR to serve Customer Load as part of a Private Microgrid Island (PMI) in any circumstance in which the Customer Load and the Resource are both disconnected from the ERCOT System due to an Outage of the transmission and/or distribution system, provided that the configuration complies with the requirements of paragraph (7) of Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and provided that the QSE or Resource Entity has notified the Transmission and/or Distribution Service Provider (TDSP) of the establishment of a PMI configuration. The QSE shall ensure that the Load served by the Resource in the PMI configuration is de-energized at the time it is reconnected to the ERCOT System following the PMI configuration. All operations in a PMI configuration and any reconnection of Load following a PMI configuration shall be coordinated with the TDSP.

(7) A TDSP shall not intentionally disconnect, or direct another TDSP to disconnect, a Generation Resource or ESR included in a PMI configuration from the ERCOT System except in the following circumstances:

(a) An approved or accepted Planned or Maintenance Outage of a Transmission Facility reasonably requires, or would otherwise result in, the disconnection of the Resource from the ERCOT System;

(b) The Resource is a Distribution Generation Resource or Distribution Energy Storage Resource (DESR), and disconnection of the Resource is required for Distribution System maintenance;

(c) The TDSP’s disconnection of the Resource is necessary to maintain the security of the TDSP’s system or the ERCOT System;

(d) The TDSP’s disconnection of the Resource is necessary to protect the public from a safety risk attributable to the operation of the Resource; or

(e) ERCOT directs the disconnection of the Resource.

(8) For each Intermittent Renewable Resource (IRR) synchronized to the ERCOT System and not capable of providing real power due to a lack of fuel, the Resource Entity and QSE shall send ERCOT, via telemetry, a Real-Time On-Line status and HSL and LSL of 0.

***6.5.7.1.13 Data Inputs and Outputs for the Real-Time Sequence and SCED***

(1) Inputs: The following information must be provided as inputs to the Real-Time Sequence and SCED. ERCOT may require additional information as required, including:

(a) Real-Time data from TSPs including status indication for each point if that data element is stale for more than 20 seconds;

|  |
| --- |
| ***[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (a) Real-Time data from TSPs and DCTOs including status indication for each point if that data element is stale for more than 20 seconds; |

(i) Transmission Electrical Bus voltages;

(ii) MW and MVAr pairs for all transmission lines, transformers, and reactors;

(iii) Actual breaker and switch status for all modeled devices; and

(iv) Tap position for auto-transformers;

(b) State Estimator results (MW and MVAr pairs and calculated MVA) for all modeled Transmission Elements;

(c) Transmission Element ratings from TSPs;

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

(i) Data from the Network Operations Model:

(A) Transmission lines – Normal, Emergency, and 15-Minute Ratings (MVA); and

(B) Transformers and Auto-transformers – Normal, Emergency, and 15-Minute Ratings (MVA) and tap position limits;

(ii) Data from QSEs:

(A) Generator Step-Up (GSU) transformers tap position;

(B) Resource HSL (from telemetry); and

(C) Resource LSL (from telemetry); and

(d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

|  |
| --- |
| ***[NPRR857: Replace paragraph (d) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs, DCTOs, or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element. |

(2) ERCOT shall validate the inputs of the Resource Limit Calculator as follows:

(a) The calculated SURAMP and SDRAMP are each greater than or equal to zero; and

(b) Other provision specified under Section 3.18, Resource Limits in Providing Ancillary Service.

|  |
| --- |
| ***[NPRR1010: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]*** |

(3) Outputs for ERCOT Operator information and possible action include:

(a) Operator notification of any change in status of any breaker or switch;

(b) Lists of all breakers and switches not in their normal position;

(c) Operator notification of all Transmission Element overloads detected from telemetered or State-Estimated data;

(d) Operator notification of all Transmission Element security violations; and

(e) Operator summary displays:

(i) Transmission system status changes;

(ii) Overloads;

(iii) System security violations; and

(iv) Base Points.

(4) Every hour, ERCOT shall post on the MIS Secure Area the following information:

(a) Status of all breakers and switches used in the NSA except breakers and switches connecting Resources to the ERCOT Transmission Grid;

(b) All binding transmission constraints and the contingency or overloaded element pairs that caused such constraint; and

(c) Shift Factors, including Private Use Network Settlement Points, by Resource Node, Hub, Load Zone, and DC Tie.

(5) Sixty days after the applicable Operating Day, ERCOT shall post on the MIS Secure Area, the following information:

(a) Hourly transmission line flows and voltages from the State Estimator, excluding transmission line flows and voltages for Private Use Networks; and

(b) Hourly transformer flows, voltages and tap positions from the State Estimator, excluding transformer flows, voltages, and tap positions for Private Use Networks.

(6) Notwithstanding paragraph (5) above, ERCOT, in its sole discretion, shall release relevant State Estimator data less than 60 days after the Operating Day if it determines the release is necessary to provide complete and timely explanation and analysis of unexpected market operations and results or system events including, but not limited to, pricing anomalies, recurring transmission congestion, and system disturbances. ERCOT’s release of data under this paragraph shall be limited to intervals associated with the unexpected market or system event as determined by ERCOT. The data release shall be made available simultaneously to all Market Participants.

(7) Every hour, ERCOT shall post on the ERCOT website, the sum of ERCOT generation, and flow on the DC Ties, all from the State Estimator.

(8) After every SCED run, ERCOT shall post to the ERCOT website the sum of the HDL and the sum of the LDL for all Generation Resources and ESRs On-Line and Dispatched by SCED.

(9) Sixty days after the applicable Operating Day, ERCOT shall post to the ERCOT website the summary LDL and HDL report from paragraph (8) above and include instances of manual overrides of HDL or LDL, including the name of the Generation Resource or ESR and the type of override.

(10) No sooner than sixty days after the applicable Operating Day, ERCOT shall provide to the appropriate Technical Advisory Committee (TAC) subcommittee instances of manual overrides of HDL or LDL, including the name of the Generation Resource or ESR, the reason for the override, and, as applicable, the cost as calculated in Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment.

(11) After every SCED run, ERCOT shall post to the MIS Certified Area, for any QSE, instances of a manual override of the HDL or LDL for a Generation Resource or ESR, including the original and overridden HDL or LDL.

**6.5.7.4 Base Points**

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

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

(b) MW output for Generation Resource, MW output or MW consumption for ESR, and MW consumption for Controllable Load Resource;

(c) Time of the Dispatch Instruction;

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

|  |
| --- |
| ***[NPRR285: Insert paragraph (e) below upon system implementation and renumber accordingly:]***  (e) Flag indicating SCED has dispatched a Generation Resource or ESR away from the Output Schedule submitted for that Resource; |

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

(f) Other information relevant to that Dispatch Instruction.

|  |
| --- |
| [NPRR1188: Insert paragraph (2) below upon system implementation:]  (2) Each Generation Resource and CLR shall follow ERCOT-issued Updated Desired Base Points plus any Regulation Service deployments, unless otherwise instructed by ERCOT. ERCOT-issued Updated Desired Base Points shall not include deployed Regulation Service or expected Primary Frequency Response. |

|  |
| --- |
| ***[NPRR1010: Insert Section 6.5.7.4.1 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  ***6.5.7.4.1 Updated Desired Set Points***  (1) Each Resource shall follow ERCOT-issued Updated Desired Set Points (UDSPs), unless otherwise instructed by ERCOT. ERCOT-issued UDSPs shall not include expected Primary Frequency Response.  (2) A UDSP is the sum of a calculated MW value representing the expected MW output (positive or negative) of a Resource ramping to a SCED Base Point and the Resource-specific Regulation Service instruction from ERCOT.  (3) LFC shall send Resource-specific UDSP to QSEs every four seconds.  (4) Resources, excluding non-Controllable Load Resources, that have been awarded RRS as FFR-capable Resources or are telemetering a Resource Status of ONSC, will all have manual deployment instructions and expected deployments triggered automatically by frequency deviations included in the UDSP value provided to the QSE for the Resource. These deployment components of UDSP will reflect the latest Ancillary Service awards and are separate from the ramping component of UDSP.  (5) When ERCOT System frequency experiences a 0.05 Hz or greater deviation from scheduled frequency, and a Resource is ramping to a SCED Base Point in a manner directionally opposite to system frequency, the ramping component of the Resource’s UDSP will be temporarily held constant and flagged accordingly. |

**6.5.7.6.2.2 Deployment of Responsive Reserve (RRS)**

(1) RRS is intended to:

(a) Help restore the frequency within the first few seconds of a significant frequency deviation of the interconnected transmission system; and

(b) Provide energy during the implementation of an EEA.

(2) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides, by one or more of the following:

(a) RRS energy deployment by automatic Governor response as a result of frequency deviation;

(b) Through use of an automatic Dispatch Instruction signal to deploy RRS capacity from Generation Resources, Energy Storage Resources (ESRs), or Controllable Load Resources providing Primary Frequency Response;

(c) By Dispatch Instructions for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System; and

(d) RRS energy deployment by automatic action of high-set under-frequency relays as a result of a significant frequency deviation.

(3) ERCOT shall deploy RRS to respond to a frequency deviation when the power requirement to restore frequency to normal ACE in ten minutes exceeds the Reg-Up ramping capability. Deployment of RRS on Load Resources, excluding Controllable Load Resources, must be as described in Section 6.5.9.4, Energy Emergency Alert.

(4) ERCOT may deploy RRS in response to system disturbance requirements as specified in the Operating Guides if no additional energy is available to be dispatched from SCED as determined by the Ancillary Service Capacity Monitor.

(5) Energy from RRS Resources may also be deployed by ERCOT under Section 6.5.9, Emergency Operations.

(6) ERCOT shall allocate the deployment of RRS proportionally among QSEs that provide RRS using Resources that are not on high-set under-frequency relays.

(7) ERCOT shall use the SCED, ECRS, and Non-Spin as soon as practicable to minimize the prolonged use of RRS energy.

(8) Once RRS is deployed, the QSE’s obligation to deliver RRS remains in effect until specifically instructed by ERCOT to stop providing RRS. However, except in an Emergency Condition, the QSE’s obligation to deliver RRS may not exceed the period for which the service was committed.

(9) Following the deployment or recall of a deployment by Dispatch Instruction of RRS, QSE shall adjust the telemetered RRS Ancillary Service Schedule of Resources providing the service and ERCOT shall adjust the HASL and LASL based on the QSE’s telemetered Ancillary Service Schedule for RRS as described in Section 6.5.7.2, Resource Limit Calculator, to account for such deployment.

(10) QSEs providing RRS and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring.

(11) For RRS deployment that is not automatic in response to frequency deviation, ERCOT shall issue RRS deployment Dispatch Instructions over ICCP for Generation Resources, ESRs, and Controllable Load Resources and XML for all other Load Resources. Those Dispatch Instructions must contain the MW output requested. For Generation Resources and Controllable Load Resources from which RRS capacity was deployed, ERCOT shall use SCED to dispatch RRS energy. The Base Points for those Resources includes RRS energy as well as any other energy dispatched by SCED.

(12) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire responsibility or, if only partial deployment is possible, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(13) RRS provided from a Generation Resource or ESR shall be responsive to frequency deviations as defined in Section 8.5.1.1, Governor in Service. Generation Resources providing RRS must have a Governor droop setting that is not greater than 5.0%.

(14) RRS provided from a Resource capable of FFR shall self-deploy their obligated response within 15 cycles after frequency drops below 59.85 Hz and must continue to provide a response until the frequency increases above that level. Resources which require recharging may do so once the frequency increases above 59.990 Hz.

(15) RRS provided by interruptible Load shall have automatic under-frequency relay setting set at no lower than 59.70 Hz

(16) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides by one or more of the following:

(a) RRS energy deployment during an EEA;

(b) By Dispatch Instructions for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System; and

(c) RRS energy deployment from Load Resources and Generation Resources operating in synchronous condenser fast-response mode by automatic action of high-set under-frequency relays as a result of a significant frequency deviation.

|  |
| --- |
| ***[NPRR1010: Replace Section 6.5.7.6.2.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  **6.5.7.6.2.2 Deployment of Responsive Reserve (RRS)**  (1) RRS is intended to:  (a) Help restore the frequency within the first few seconds of a significant frequency deviation of the interconnected transmission system; and  (b) Provide energy during the implementation of an EEA.  (2) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides, by one or more of the following:  (a) RRS energy deployment by automatic Governor response as a result of frequency deviation;  (b) By Dispatch Instruction for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System;  (c) RRS energy deployment by automatic action of high-set under-frequency relays as a result of a significant frequency deviation; and  (d) By Dispatch Instruction for deployment of RRS from Resources with a Resource Status of ONSC or Resources providing FFR.  (3) ERCOT shall deploy RRS to respond to a frequency deviation when the power requirement to restore frequency to normal ACE in ten minutes exceeds the Reg-Up ramping capability. Deployment of RRS on Load Resources, excluding Controllable Load Resources, must be as described in Section 6.5.9.4, Energy Emergency Alert.  (4) Energy from RRS Resources may also be deployed by ERCOT under Section 6.5.9, Emergency Operations.  (5) For Resources providing RRS with a Resource Status of ONSC, ERCOT shall deploy RRS as described in Section 6.5.9.4.2, EEA Levels, and Nodal Operating Guide Section 2.3.1.2, Additional Operational Details for Responsive Reserve Providers.  (6) For Resources providing RRS with FFR, ERCOT may manually deploy the FFR RRS in an attempt to recover frequency to meet NERC Performance Control Standards after utilizing Reg-Up and the SCED process which includes off-cycle SCED executions.  (7) ERCOT shall use the SCED, ECRS, and Non-Spin as soon as practicable to minimize the prolonged use of RRS energy.  (8) Once RRS is manually deployed on Load Resources controlled by under-frequency relays or Resources telemetering a Resource Status of ONSC, the Resource’s obligation to deliver RRS remains in effect until recalled by ERCOT.  (9) Resources providing RRS and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring.  (10) ERCOT shall issue RRS deployment Dispatch Instructions over ICCP for Generation Resources awarded RRS with a Resource Status of ONSC, and SCED-dispatchable Resources providing FFR. Dispatch Instructions must contain the MW output requested. UDSPs for those Resources includes RRS energy deployments as well as any other energy dispatched by SCED.  (11) ERCOT shall issue RRS deployment Dispatch Instructions, specifying the required MW output, through Extensible Markup Language (XML) for non-Controllable Load Resources.  (12) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire award or, if only partial deployment is needed, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.  (13) RRS provided from a Generation Resource or ESR shall be responsive to frequency deviations as defined in Section 8.5.1.1, Governor in Service. Generation Resources and ESRs providing RRS must have a Governor droop setting that is not greater than 5.0%.  (14) RRS provided from a Resource capable of FFR shall self-deploy their obligated response within 15 cycles after frequency drops below 59.85 Hz and must continue to provide a response until the frequency increases above that level. Resources which require recharging may do so once the frequency increases above 59.990 Hz.  (15) RRS provided by interruptible Load shall have automatic under-frequency relay setting set at no lower than 59.70 Hz.  (16) ERCOT shall deploy RRS to meet NERC Control Performance Standards and other performance criteria as specified in these Protocols and the Operating Guides by one or more of the following:  (a) RRS energy deployment during an EEA;  (b) By Dispatch Instructions for deployment of RRS energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System; and  (c) RRS energy deployment from Load Resources and Generation Resources operating in synchronous condenser fast-response mode by automatic action of high-set under-frequency relays as a result of a significant frequency deviation. |

**6.5.7.6.2.3 Non-Spinning Reserve Service Deployment**

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

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

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

(4) Non-Spin can be provided by Controllable Load Resources that are SCED qualified or by Load Resources that are not Controllable Load Resources but do not have an under-frequency relay or the under-frequency relay is not armed. A Load Resource that is not a Controllable Load Resource shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity. Following a deployment instruction, the QSE shall reduce the Non-Spin Ancillary Service Schedule by the amount of the deployment.

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

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

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

(6) Subject to the exceptions described in paragraphs (a) and (b) below, On-Line Generation Resources, ESRs, and Controllable Load Resources that are assigned Non-Spin Ancillary Service Resource Responsibility during an Operating Hour shall always be deployed in that Operating Hour. This deployment shall be considered as a standing Protocol-directed Non-Spin deployment Dispatch Instruction. Within the 30-second window prior to the top-of-hour clock interval described in paragraph (2) of Section 6.3.2, Activities for Real-Time Operations, the QSE shall respond to the standing Non-Spin deployment Dispatch Instruction for those Resources assigned Non-Spin Ancillary Service Resource Responsibility effective at the top-of-hour by adjusting the Non-Spin Ancillary Service Schedule telemetry. For a Generation Resource, the QSE shall set the Non-Spin Ancillary Service Schedule telemetry equal to the portion of Non-Spin being provided from power augmentation if the portion being provided from power augmentation is participating as Off-Line Non-Spin, otherwise it shall be set to 0. For a Controllable Load Resource, the QSE shall set the Non-Spin Ancillary Service Schedule telemetry equal to 0. As described in Section 6.5.7.2, Resource Limit Calculator, ERCOT shall adjust the HASL and LASL based on the QSE’s telemetered Non-Spin Ancillary Service Schedule to account for such deployment and to make the energy from the full amount of the Non-Spin Ancillary Service Resource Responsibility available to SCED. A Non-Spin deployment Dispatch Instruction from ERCOT is not required and these Resources must be able to Dispatch their Non-Spin Ancillary Service Resource Responsibility in response to a SCED Base Point deployment instruction. The provisions of this paragraph (5) do not apply to:

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

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

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

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

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

(10) Each QSE providing Non-Spin from a Resource shall inform ERCOT of the Non-Spin Resource availability using the Resource Status and Non-Spin Ancillary Service Resource Responsibility indications for the Operating Hour using telemetry and shall use the COP to inform ERCOT of Non-Spin Resource Status and Non-Spin Ancillary Service Resource Responsibility for hours in the Adjustment Period through the end of the Operating Day.

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

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

(a) The Resource name;

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

(c) The anticipated duration of deployment.

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

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

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

|  |
| --- |
| [NPRR1000, NPRR1010, and NPRR1188: Replace applicable portions of Section 6.5.7.6.2.3 above with the following upon system implementation for NPRR1000 or NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]  **6.5.7.6.2.3 Non-Spinning Reserve Service Deployment**  (1) ERCOT shall deploy Non-Spin Service by operator Dispatch Instruction for the portion of On-Line Generation Resources that is only available through power augmentation and participating as Off-Line Non-Spin and Off-Line Generation Resources. ERCOT shall develop a procedure approved by TAC to deploy Resources providing Non-Spin Service. ERCOT Operators shall implement the deployment procedure when a specified threshold(s) in MW of capability available to SCED to increase generation is reached. ERCOT Operators may implement the deployment procedure to recover deployed RRS, ECRS, or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that awarded on an individual Resource.  (2) Once Non-Spin capacity from Off-Line Generation Resources awarded Non-Spin is deployed and the Generation Resources are On-Line, ERCOT shall use SCED to determine the amount of energy to be dispatched from those Resources.  (3) Off-Line Generation Resources offering to provide Non-Spin must provide an Energy Offer Curve for use by SCED.  (4) Non-Spin can be provided by CLRs that are SCED qualified or by Load Resources that are not CLRs but do not have an under-frequency relay or the under-frequency relay is unarmed.  (a) CLRs awarded Non-Spin shall have an Energy Bid Curve for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service award within 30 minutes, using the Resource’s Normal Ramp Rate curve. An Aggregate Load Resource (ALR) must comply with all requirements in Section 22, Attachment O, Requirements for Aggregate Load Resource Participation in the ERCOT Markets.  (b) A Load Resource that is not a CLR shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity.  (5) Off-Line Generation Resources awarded Non-Spin, while Off-Line and before the receipt of any deployment instruction, shall be capable of being dispatched to their Non-Spin award within 30 minutes of a Dispatch Instruction. On-Line Generation Resources awarded Non-Spin on the power augmentation capacity shall be capable of being dispatched to their Non-Spin award within 30 minutes of a Dispatch Instruction.  (6) ERCOT may deploy Non-Spin at any time in a Settlement Interval.  (7) ERCOT shall develop a process to place Off-Line Generation Resources and Load Resources that are not CLRs with Non-Spin award in a group based on a random sampling for the purpose of deploying these Resources manually. At ERCOT’s discretion, ERCOT may deploy all groups as specified in the Other Binding Document titled “Non-Spinning Reserve Deployment and Recall Procedure.”  (a) On-Line Generation Resources participating in Off-Line Non-Spin using power augmentation will be randomly distributed in Real-Time among the groups created in the Day-Ahead for the purpose of manual deployment of Non-Spin by operator Dispatch Instruction.  (b) Any Generation Resource providing Off-Line Non-Spin that did not previously receive group assignment will be automatically considered in Group 1. Any Load Resource that is not a CLR providing Non-Spin in Real-Time that did not previously receive group assignment will be automatically considered in Group 1. ERCOT may assign a Generation Resource providing Off-Line Non-Spin or a Load Resource that is not a CLR to another group if that Resource did not previously receive group assignment and, in ERCOT’s reasonable judgment, Group 1 is too large.  (8) ERCOT’s Non-Spin deployment Dispatch Instructions must include:  (a) The Resource name;  (b) A MW level of capacity deployment for Generation Resources with Energy Offer Curve, a MW level for ESRs with Energy Bid/Offer Curve, and a MW level of energy for Generation Resources with Output Schedules and a Dispatch Instruction for Load Resources, excluding CLRs, at a minimum equal to their awarded Non-Spin Ancillary Service amount; and  (c) The anticipated duration of deployment.  (9) ERCOT shall provide a signal via ICCP to the QSE of a deployed Resource indicating that its Non-Spin capacity has been deployed.  (10) ERCOT shall, as part of its TAC-approved Non-Spin deployment procedure, provide for the recall of Non-Spin from On-Line Resources that were previously Off-Line Resources providing Non-Spin capacity and from On-Line Resources providing Non-Spin through power augmentation.  (11) ERCOT shall provide a notification to all QSEs via the ERCOT website when any Non-Spin capacity is deployed on the ERCOT System showing the time, MW quantity and the anticipated duration of the deployment. |

**6.5.7.6.2.4 Deployment and Recall of ERCOT Contingency Reserve Service**

(1) ECRS is intended to:

(a) Help restore the frequency to 60 Hz within ten minutes of a significant frequency deviation;

(b) Provide energy to avoid, or during the implementation of, an EEA;

(c) Provide backup to Reg-Up; and

(d) Provide energy upon detection of insufficient available capacity for net load ramps.

(2) ERCOT shall deploy ECRS to meet NERC Standards and other performance criteria as specified in these Protocols and the Operating Guides by taking one or more of the following actions:

(a) Automatic Dispatch Instruction signal to release ECRS capacity from Generation Resources and Controllable Load Resources to SCED; and/or

(b) Dispatch Instruction for deployment of energy from Load Resources via electronic Messaging System.

(3) ERCOT shall release ECRS from Generation Resources and Controllable Load Resources to SCED when frequency drops below 59.91 Hz and available Reg-Up is not sufficient to restore frequency. Upon deployment of Off-Line ECRS from a QSGR providing ECRS, the Resource’s Ancillary Service Schedule for ECRS must be adjusted for the ERCOT instructed ECRS deployment and the Resource’s status must be set to OFFQS to be available for dispatch by SCED. Once recalled QSGRs providing ECRS must follow the decommitment process outlined in Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process.

(4) Energy from Resources providing ECRS may also be manually deployed by ERCOT pursuant to Section 6.5.9, Emergency Operations.

(5) ERCOT shall use SCED and Non-Spin as soon as practicable to recover ECRS reserves.

(6) Following an ECRS deployment to SCED-dispatchable Resources, the QSE’s obligation to deliver ECRS remains in effect until ERCOT issues a recall instruction or its ECRS obligation expires, whichever occurs first. Following an ECRS deployment to Load Resources, excluding Controllable Load Resources, or Resources operating in synchronous condenser fast-response mode, the QSE’s obligation to deliver ECRS remains in effect until ERCOT issues a recall instruction.

(7) Following a deployment or recall Dispatch Instruction of ECRS, a QSE shall adjust the telemetered ECRS Ancillary Service Schedule for the Resource providing the service and ERCOT shall adjust the HASL based on the QSE’s telemetered Ancillary Service Schedule for ECRS, as described in Section 6.5.7.2, Resource Limit Calculator, to account for such deployment.

(8) For Generation Resources and Controllable Load Resources providing ECRS, Base Points include ECRS energy as well as any other energy dispatched by SCED. A Resource must be able to be fully dispatched by SCED to its ECRS Ancillary Service Resource Responsibility within the ten-minute time frame according to its telemetered Emergency Ramp Rate.

(9) Each QSE providing ECRS shall meet the deployment performance requirements specified in Section 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria.

(10) ERCOT shall issue instructions to release ECRS capacity provided from Generation Resources and Controllable Load Resources to SCED over ICCP and shall issue deployment instructions for Load Resources providing ECRS via XML. Such instructions shall contain the MW requested.

(11) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire Ancillary Service Resource Responsibility or, if only partial deployment is possible, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(12) ERCOT shall recall automatically deployed ECRS capacity once system frequency recovers above 59.97 Hz.

(13) ERCOT shall recall ECRS deployment provided from a Load Resource that is not a Controllable Load Resource once PRC is above a pre-defined threshold, as described in the Operating Guides.

|  |
| --- |
| ***[NPRR1010: Replace Section 6.5.7.6.2.4 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  **6.5.7.6.2.4Deployment and Recall of ERCOT Contingency Reserve Service**  (1) ECRS is intended to:  (a) Help restore the frequency to 60 Hz within ten minutes of a significant frequency deviation;  (b) Provide energy to avoid, or during the implementation of, an EEA;  (c) Provide backup to Reg-Up; and  (d) Provide energy upon detection of insufficient available capacity for net load ramps.  (2) ERCOT shall deploy ECRS to meet NERC Standards and other performance criteria as specified in these Protocols and the Operating Guides by taking one or more of the following actions:  (a) ERCOT shall issue ECRS deployment Dispatch Instructions, specifying the required MW output, over ICCP for Resources awarded ECRS with a Resource Status of ONSC.  (b) Dispatch Instruction for deployment of energy from Load Resources via electronic Messaging System.  (3) Energy from Resources providing ECRS may also be manually deployed by ERCOT pursuant to Section 6.5.9, Emergency Operations.  (4) ERCOT shall use SCED and Non-Spin as soon as practicable to recover ECRS reserves.  (5) Following a manual ECRS deployment to Load Resources, excluding Controllable Load Resources, or Resources telemetering a Resource Status of ONSC, the QSE’s obligation to deliver ECRS remains in effect until ERCOT issues a recall instruction.  (6) For Generation Resources, ESRs, and Controllable Load Resources providing ECRS, Base Points include ECRS energy as well as any other energy dispatched by SCED. A Resource must be able to be fully dispatched by SCED to its ECRS Ancillary Service award within the ten-minute time frame according to its telemetered ramp rate that reflects the Resource’s capability of providing ECRS.  (7) Each Resource providing ECRS shall meet the deployment performance requirements specified in Section 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria.  (8) ERCOT shall issue deployment instructions for Load Resources providing ECRS via XML. Such instructions shall contain the MW requested.  (9) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire Ancillary Service award or, if only partial deployment is possible, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.  (10) ERCOT shall recall deployed ECRS capacity provided from Resource telemetering Resource Status of ONSC once system frequency recovers above 59.98 Hz.  (11) ERCOT shall recall ECRS deployment provided from a Load Resource that is not a Controllable Load Resource once PRC is above a pre-defined threshold, as described in the Operating Guides. |

**6.5.7.8 Dispatch Procedures**

(1) ERCOT shall issue all Resource Dispatch Instructions to the QSE that represents the affected Resource. ERCOT and QSEs are responsible for complying with Dispatch Instructions as prescribed in the Nodal Operating Guides. A QSE may provide a Resource Status of ONTEST for a Generation Resource or ESR not providing Ancillary Services to indicate that the Resource is currently undergoing unit testing and is blocked from SCED Dispatch. A QSE may provide a Resource Status of STARTUP for a Generation Resource or ESR not providing Ancillary Services to indicate that the Resource is currently undergoing a start-up sequence which requires manual control below or above its telemetered LSL to stabilize the Resource prior to its availability for SCED Dispatch. Generation Resources and ESRs with a Resource Status of ONTEST will be provided a Base Point equal to the net real power telemetry at the time of the SCED execution. ERCOT may not issue Dispatch Instructions to the QSE for Generation Resources or ESRs with a Resource Status of ONTEST except:

(a) For Dispatch Instructions that are a part of testing; or

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

(c) During Force Majeure Events that threaten the reliability of the ERCOT System.

(2) Each QSE shall immediately forward any valid Dispatch Instruction to the appropriate Resource or group of Resources or identify a reason for non-compliance with the Dispatch Instruction to ERCOT in accordance with Section 6.5.7.9, Compliance with Dispatch Instructions.

(3) If ERCOT believes that a Resource has inadequately responded to a Dispatch Instruction, ERCOT shall notify the QSE representing the Resource as soon as practicable.

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

(5) By mutual agreement of the TSP and ERCOT, Dispatch Instructions to the TSP may be provided to the TSP’s TO. In that case, issuance of the Dispatch Instruction to the TO is considered issuance to the TSP, and the TSP must comply with the Dispatch Instruction exactly as if it had been issued directly to the TSP, whether or not the TO accurately conveys the Dispatch Instruction to the TSP.

|  |
| --- |
| ***[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (5) By mutual agreement of the TSP, DCTO, and ERCOT, Dispatch Instructions to the TSP or DCTO may be provided to the TSP’s or DCTO’s Transmission Operator (TO). In that case, issuance of the Dispatch Instruction to the TO is considered issuance to the TSP or DCTO, and the TSP or DCTO must comply with the Dispatch Instruction exactly as if it had been issued directly to the TSP or DCTO, whether or not the TO accurately conveys the Dispatch Instruction to the TSP or DCTO. |

(6) ERCOT shall direct VDIs to the Master QSE of a Generation Resource that has been split to function as two or more Split Generation Resources as deemed necessary by ERCOT to effectuate actions for the total Generation Resource for instances in which electronic instructions are not feasible.

***6.5.8 Verbal Dispatch Instruction Confirmation***

(1) Following the issuance of a VDI by ERCOT to a QSE for a Generation Resource or ESR, ERCOT will provide the QSE with an electronic confirmation of the VDI for Settlement purposes.

(2) A VDI confirmation shall contain the following information:

(a) Operating Day and time ERCOT issued the VDI;

(b) Identification of the QSE for the Resource(s) subject to the VDI, and instructing authority (including the names of the ERCOT Operator and individual that received the VDI);

(c) Identification of the specific Resource(s) subject to the VDI;

(d) Specific actions required of the Resource(s);

(e) Beginning operating level or state of the Resource(s);

(f) Instructed operating level or state of the Resource(s);

(g) Time at which the Resource(s) was required to initiate actions;

(h) Time by which the Resource(s) was required to complete actions; and

(i) Other information relevant to that Dispatch Instruction.

(3) Following receipt by the QSE of the VDI confirmation issued by ERCOT, the QSE shall provide ERCOT with electronic acknowledgement of the VDI confirmation.

**6.5.9.4 Energy Emergency Alert**

(1) At times it may be necessary to reduce ERCOT System Demand because of a temporary decrease in available electricity supply. To provide orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT shall initiate and coordinate the implementation of the EEA following the steps set forth below in Section 6.5.9.4.2, EEA Levels.

(2) The goal of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT System to reduce the chance of cascading Outages.

(3) ERCOT’s operating procedures must meet the following goals:

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

(b) Use of RRS, ECRS, other Ancillary Services, and ERS to the extent permitted by ERCOT System conditions;

(c) Maximum use of ERCOT System capability;

(d) Maintenance of station service for nuclear-powered Generation Resources;

(e) Securing startup power for Generation Resources;

(f) Operation of Generation Resources and ESRs during loss of communication with ERCOT;

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

(h) Management of Interconnection Reliability Operating Limits (IROLs) shall not change.

(4) ERCOT is responsible for coordinating with QSEs, TSPs, and DSPs to monitor ERCOT System conditions, initiating the EEA levels, notifying Market Participants, and coordinating the implementation of the EEA levels while maintaining transmission security limits.

|  |
| --- |
| ***[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]***  (4) ERCOT is responsible for coordinating with QSEs, DCTOs, TSPs, and DSPs to monitor ERCOT System conditions, initiating the EEA levels, notifying Market Participants, and coordinating the implementation of the EEA levels while maintaining transmission security limits. |

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

(6) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using the DC Ties or by using BLTs to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with NERC scheduling guidelines.

(7) Some of the EEA steps are not applicable if transmission security violations exist. There may be insufficient time to implement all EEA levels in sequence, however, to the extent practicable, ERCOT shall use Ancillary Services that QSEs have made available in the market to maintain or restore reliability.

|  |
| --- |
| ***[NPRR1010: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (7) Some of the EEA steps are not applicable if transmission security violations exist. There may be insufficient time to implement all EEA levels in sequence, however, to the extent practicable, ERCOT shall use Ancillary Service capabilities of Resources in the market to maintain or restore reliability. |

(8) ERCOT may immediately implement EEA Level 2 when clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT may immediately implement EEA Level 3 any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz for any duration of time. ERCOT shall immediately implement EEA Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

(9) Percentages for EEA Level 3 Load shedding will be based on the previous year’s TSP peak Loads, as reported to ERCOT, and must be reviewed by ERCOT and modified annually as required.

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(a) of Section 6.5.9.4.1, General Procedures Prior to EEA Operations, ERCOT may control the post-contingency flow to within the 15-Minute Rating in SCED. After PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(11) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(b) of Section 6.5.9.4.1, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all other double-circuit contingencies identified in paragraph (3)(b) of Section 6.5.9.4.1, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency after PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

***6.5.9.4.2 EEA Levels***

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

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

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

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

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

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

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

(b) QSEs shall:

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

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

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

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

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

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (ii) above with the following upon system implementation:]***  (ii) Ensure that each of its ESRs and SOESSs suspends charging until the EEA is recalled, except under the following circumstances:  (A) The ESR has a current SCED Base Point Instruction, LFC Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;  (B) The ESR or SOESS is actively providing Primary Frequency Response; or  (C) The ESR or SOESS is co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained. |

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (a) above with the following upon system implementation:]***  (a) Instruct ESRs to suspend charging. For ESRs, the suspension instruction shall be issued via a SCED Base Point, or, if otherwise necessary, via a manual Dispatch Instruction. An ESR shall suspend charging unless it is providing Primary Frequency Response, has received a charging instruction via SCED Base Point, or is carrying Reg-Down and has received a charging instruction from LFC. An SOESS shall suspend charging unless it is providing Primary Frequency Response. However, an ESR or SOESS co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained. |

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

(i) TOs and TDSPs may shed Load connected to under-frequency relays pursuant to an ERCOT Load shed directive issued during EEA Level 3 so long as each affected TO continues to comply with its Under-Frequency Load Shed (UFLS) obligation as described in Nodal Operating Guide Section 2.6.1, Automatic Firm Load Shedding, and its Load shed obligation as described in Nodal Operating Guide Section 4.5.3.4, Load Shed Obligation.

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

**6.6.3.6 Real-Time High Dispatch Limit Override Energy Payment**

(1) If ERCOT directs a reduction in a Generation Resource’s real power output by employing a manual High Dispatch Limit (HDL) override, or issues a Verbal Dispatch Instruction (VDI) to a Generation Resource to adjust its operation to produce the same effect, and the reduction causes the QSE to suffer a demonstrable financial loss, the QSE may be eligible for a Real-Time High Dispatch Limit Override Energy Payment, as calculated below, upon providing documented proof of that loss. In order to qualify for this payment the QSE must:

(a) Have complied with ERCOT Dispatch Instructions to reduce real power output;

(b) Have either received a SCED Base Point equal to the Resource’s HDL override value or received a SCED Base Point less than the Resource’s output level at the time of the instruction but greater than or equal to the instructed operating level specified in the VDI, during the 15-minute Settlement Interval;

(c) Have incurred a demonstrable financial loss associated with variable cost components of DAM obligations or energy purchase or sale provisions of bilateral contracts (as opposed to lost opportunity costs), in consequence of the HDL override or VDI that had an equivalent effect; and

(d) File a timely Settlement and billing dispute, including the following items:

(i) An attestation signed by an officer or executive with authority to bind the QSE;

(ii) The dollar amount and calculation of the financial loss by Settlement Interval;

(iii) An explanation of the nature of the loss and how it was attributable to the HDL override or equivalent VDI issued by ERCOT; and

(iv) Sufficient documentation to support the QSE’s calculation of the amount of the financial loss.

(2) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 business days of ERCOT’s request. ERCOT will provide Notice of its acceptance or rejection of the claim for the High Dispatch Limit Override Energy Payment within 15 Business Days of the updated submission.

(3) The Energy Offer Curve used to calculate the Real-Time High Dispatch Limit Override Energy Payment will be the most recent valid Energy Offer Curve received by ERCOT that was effective for the disputed interval(s) when the HDL override or equivalent VDI was issued. If no curve exists for the interval being disputed, ERCOT will use the most recent valid Energy Offer Curve received before the HDL override or equivalent VDI was issued for an interval prior to the disputed interval(s).

The payment shall be calculated as follows:

**HDLOEAMT *q, r, p, i* = (-1) \* Min {HDLOAL *q, r, p, i,* Max(0, ((RTSPP *p, i* – RTRSVPOR *i* – RTRDP *i* – RTEOCOST *q, r, i*) \* HDLOQTY *q, r, p, i*))}**

Where:

HDLOQTY *q, r, p, i* = Max(0, (¼ (HDLOBRKP *q, r, p, i* – AVGHDL *q, r, p, i*)))

HDLOBRKP *q, r, p, i* = Min(AVGHASL *q, r, p, i*, HDLOBRKPCP *q, r, p, i*)

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| HDLOAL ***q, r, p, i*** | $ | *High Dispatch Limit override attested losses*—The financial loss to the QSE due to the HDL override as attested by the QSE in accordance with paragraph (1)(d) above. |
| HDLOEAMT ***q, r, p, i*** | $ | *High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. |
| HDLOBRKP ***q, r, p, i*** | MW | *High Dispatch Limit override break point per QSE per Resource*—The point on the Energy Offer Curve corresponding to the lesser of the AVGHASL or the interception between the RTSPP of the Generation Resource *r* represented by QSE *q* minus the Real-Time Reserve Price for On-Line Reserves and the Real-Time On-Line Reliability Deployment Price and the Energy Offer Curve of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. |
| AVGHDL ***q, r, p, i*** | MW | *Average High Dispatch Limit per QSE per Settlement Point per Resource*—The time-weighted average of all 4-second HDL values calculated by the Resource Limit Calculator, subject to the maximum of the manual HDL override or equivalent VDI and the telemetered output or consumption, for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*.  For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. |
| AVGHASL ***q, r, p, i*** | MW | *Average High Ancillary Service Limit per QSE per Settlement Point per Resource*—The time-weighted average High Ancillary Service Limit (HASL) calculated every four seconds by the Resource Limit Calculator for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*.  For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. In the case of a VDI that is equivalent to an HDL override, this value is set equal to the HASL of Generation Resource or Controllable Load Resource *r* at the time that the VDI is issued to the QSE. |
| HDLOBRKPCP*q, r, p, i* | MW | *High Dispatch Limit override break point at clearing price per QSE per Resource*—The MW value on the Energy Offer Curve corresponding to the Real-Time Settlement Point Price of Generation Resource *r* represented by QSE *q* at Settlement Point *p* minus the Real-Time Reserve Price for On-Line Reserves and the Real-Time On-Line Reliability Deployment Price. For a combined cycle Resource, *r* is a Combined Cycle Train. |
| RTEOCOST *q, r, i* | $/MWh | Real-Time Energy Offer Curve Cost Cap—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource’s generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| HDLOQTY *q, r, p, i* | MWh | *High Dispatch Limit override quantity per QSE per Generation Resource—*The difference between the HDLOBRKP and the AVGHDL due to an ERCOT-issued HDL override or equivalent VDI for Generation Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. |
| RTSPP *p, i* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*. |
| RTRSVPOR *i* | $/MWh | *Real-Time Reserve Price for On-Line Reserves*⎯The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*. |
| RTRDP *i* | $/MWh | *Real-Time On-Line Reliability Deployment Price*⎯The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder. |
| *q* | none | A QSE. |
| *r* | none | A Generation Resource. |
| *p* | none | A Resource Node Settlement Point. |
| *i* | none | A 15-minute Settlement Interval. |

(4) The total compensation to each QSE for an HDL override for the 15-minute Settlement Interval is calculated as follows:

**HDLOEAMTQSETOT *q, i*  = HDLOEAMT *q, r, p, i***

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| HDLOEAMT *q, r, p, i* | $ | *High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. |
| HDLOEAMTQSETOT *q, i* | $ | *High Dispatch Limit override energy amount QSE total per QSE*—The total of the energy payments to QSE *q* as compensation for HDL overrides for this QSE for the 15-minute Settlement Interval *i*. |
| *Q* | none | A QSE. |
| *R* | none | A Generation Resource. |
| *P* | none | A Resource Node Settlement Point. |
| *I* | none | A 15-minute Settlement Interval. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1010: Replace Section 6.6.3.6 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  **6.6.3.6 Real-Time High Dispatch Limit Override Energy Payment**  (1) If ERCOT directs a Generation Resource or Energy Storage Resource (ESR) to reduce real power output by employing a manual High Dispatch Limit (HDL) override, or issues a Verbal Dispatch Instruction (VDI) to a Generation Resource or ESR to adjust its operation to produce the same effect, and the reduction causes the QSE to suffer a demonstrable financial loss, the QSE may be eligible for a Real-Time High Dispatch Limit Override Energy Payment, as calculated below, upon providing documented proof of that loss. In order to qualify for this payment the QSE must:  (a) Have complied with ERCOT Dispatch Instructions to reduce real power output;  (b) Have either received a SCED Base Point equal to the Resource’s HDL override value or received a SCED Base Point less than the Resource’s output level at the time of the instruction but greater than or equal to the instructed operating level specified in the VDI, during the 15-minute Settlement Interval;  (c) Have incurred a demonstrable financial loss associated with variable cost components of DAM obligations or energy purchase or sale provisions of bilateral contracts (as opposed to lost opportunity costs), in consequence of the HDL override or VDI that had an equivalent effect; and  (d) File a timely Settlement and billing dispute, including the following items:  (i) An attestation signed by an officer or executive with authority to bind the QSE;  (ii) The dollar amount and calculation of the financial loss by Settlement Interval;  (iii) An explanation of the nature of the loss and how it was attributable to the HDL override or equivalent VDI issued by ERCOT; and  (iv) Sufficient documentation to support the QSE’s calculation of the amount of the financial loss.  (2) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT’s request. ERCOT will provide Notice of its acceptance or rejection of the claim for the High Dispatch Limit Override Energy Payment within 15 Business Days of the updated submission.  (3) The Energy Offer Curve or Energy Bid/Offer Curve used to calculate the Real-Time High Dispatch Limit Override Energy Payment will be the most recent valid Energy Offer Curve or Energy Bid/Offer Curve received by ERCOT that was effective for the disputed interval(s) when the HDL override or equivalent VDI was issued. If no curve exists for the interval being disputed, ERCOT will use the most recent valid Energy Offer Curve or Energy Bid/Offer Curve received before the HDL override or equivalent VDI was issued for an interval prior to the disputed interval(s).  (4) The amount recoverable under this section shall be offset by any Ancillary Service Imbalance revenues received by the QSE that the QSE would not have earned had ERCOT not issued an HDL override.  The payment shall be calculated as follows:  **HDLOEAMT *q, r, p, i* = (-1) \* Min {HDLOAL *q, r, p, i,* Max(0, ((RTSPP *p, i* – RTRDP *i* – RTEOCOST *q, r, i*) \* HDLOQTY *q, r, p, i*))}**  Where:  HDLOQTY *q, r, p, i* = Max(0, (¼ (HDLOBRKP *q, r, p, i* – AVGHDL *q, r, p, i*)))  HDLOBRKP *q, r, p, i* = Min(AVGHSL *q, r, p, i*, HDLOBRKPCP *q, r, p, i*)  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | HDLOAL ***q, r, p, i*** | $ | *High Dispatch Limit override attested losses*—The financial loss to the Resource *r* represented by QSE *q* due to the HDL override as attested by the QSE in accordance with paragraph (1)(d) above. For a combined cycle Resource, *r* is a Combined Cycle Train. | | HDLOEAMT ***q, r, p, i*** | $ | *High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. | | HDLOBRKP ***q, r, p, i*** | MW | *High Dispatch Limit override break point per QSE per Resource*—The point on the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the lesser of the AVGHSL or the interception between the RTSPP of the Resource *r* represented by QSE *q* minus the Real-Time Reliability Deployment Price for Energy and the Energy Offer Curve Cost Cap of Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. | | AVGHDL ***q, r, p, i*** | MW | *Average High Dispatch Limit per QSE per Settlement Point per Resource*—The time-weighted average of all 4-second HDL values calculated by the Resource Limit Calculator, subject to the maximum of the manual HDL override or equivalent VDI and the telemetered output, for the Generation Resource or ESR *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*.  For a Combined Cycle Train, the Resource *r* is a Combined Cycle Train. | | AVGHSL ***q, r, p, i*** | MW | *Average High Sustained Limit per QSE per Settlement Point per Resource*—The time-weighted average High Sustained Limit (HSL) for the Generation Resource or ESR *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*.  For a Combined Cycle Train, the Resource *r* is a Combined Cycle Train. In the case of a VDI that is equivalent to an HDL override, this value is set equal to the HSL of Generation Resource, or ESR *r* at the time that the VDI is issued to the QSE. | | HDLOBRKPCP*q, r, p, i* | MW | *High Dispatch Limit override break point at clearing price per QSE per Resource*—The MW value on the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the Real-Time Settlement Point Price of Resource *r* represented by QSE *q* at Settlement Point *p* minus the Real-Time Reliability Deployment Price for Energy. For a combined cycle Resource, *r* is a Combined Cycle Train. | | RTEOCOST *q, r, i* | $/MWh | *Real-Time Energy Offer Curve Cost Cap—*The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource’s generation above the Low Sustained Limit (LSL) for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | HDLOQTY *q, r, p, i* | MWh | *High Dispatch Limit override quantity per QSE per Generation Resource—*The difference between the HDLOBRKP and the AVGHDL due to an ERCOT-issued HDL override or equivalent VDI for Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. | | RTSPP *p, i* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*. | | RTRDP *i* | $/MWh | *Real-Time Reliability Deployment Price* *for Energy*⎯The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | *q* | none | A QSE. | | *r* | none | A Generation Resource or ESR. | | *p* | none | A Resource Node Settlement Point. | | *i* | none | A 15-minute Settlement Interval. |   (5) The total compensation to each QSE for an HDL override for the 15-minute Settlement Interval is calculated as follows:  **HDLOEAMTQSETOT *q, i*  = HDLOEAMT *q, r, p, i***  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | HDLOEAMT *q, r, p, i* | $ | *High Dispatch Limit override energy amount per QSE per Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train. | | HDLOEAMTQSETOT *q, i* | $ | *High Dispatch Limit override energy amount QSE total per QSE*—The total of the energy payments to QSE *q* as compensation for HDL overrides for this QSE for the 15-minute Settlement Interval *i*. | | *Q* | none | A QSE. | | *R* | none | A Generation Resource or ESR. | | *P* | none | A Resource Node Settlement Point. | | *i* | none | A 15-minute Settlement Interval. | |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR879, NPRR963, and NPRR1010: Replace applicable portions of Section 6.6.5.1.1.1 above with the following upon system implementation for NPRR879 or NPRR963; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; and renumber accordingly:]***  **6.6.5.2 Set Point Deviation Charge for Over Generation**  (1) ERCOT shall charge a QSE for a Generation Resource, including an Intermittent Renewable Resource (IRR) with an Ancillary Service award for at least one SCED interval within the 15-minute Settlement Interval, for over-generation that exceeds the following tolerance. The tolerance is the greater of:  (a) 5% of the AASP in the Settlement Interval; or  (b) Five MW above the AASP in the Settlement Interval.  (2) For instances in which an IRR has not received an Ancillary Service award or is not part of an IRR Group in which an IRR receives an Ancillary Service award for any SCED interval within the 15-minute Settlement Interval, Set Point Deviation Charges will be determined per Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge.  (3) The over-generation charge to each QSE for each Generation Resource, that is not part of an IRR Group at each Resource Node Settlement Point is calculated as follows:  **SPDAMT *q, r, p, i*  = Max (PR1, RTSPP *p, i*) \* OGEN *q, r, p, i***  Where:  OGEN *q, r, p, i*  = Max [0, (TWTG *q, r, p, i*  – ¼ \* Max (((1 + K1) \* AASP *q, r, p, i*), (AASP *q, r, p, i* + Q1)))]  TWTG *q, r, p, i =* ( (AVGTG5M *q, r, p, i, y*) / 3) \* ¼  (4) If any IRR in an IRR Group is awarded Ancillary Services for at least one SCED interval within the 15-minute Settlement Interval, then the deviation penalty is determined for the IRR Group and evenly allocated and charged to each IRR within that IRR Group as follows:  **SPDAMT *q, r, p, i* = Max (PR1, RTSPP *p, i*) \* OGEN *q, r, p, i***  Where:  OGEN *q, r, p, i*  = Max [0, (TWTG *q, wg, p, i*  – ¼ \* Max (((1 + K1) \* AASP *q, wg, p, i*),  (AASP *q, wg, p, i* + Q1)))] / N  TWTG *q, wg, p, i* =  ( (AVGTG5M *q, r, p, i, y*) / 3) \* ¼  AASP *q, wg, p, i* = (AASP *q, r, p, i*)  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | SPDAMT *q, r, p, i* | $ | *Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*. The Set Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources. | | RTSPP *p, i* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*. | | TWTG *q, r, p, i* | MWh | *Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | AASP *q, r, p, i* | MW | *Average Aggregated Set Point per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Generation Resource *r* represented by QSE *q* at Settlement Point *p,* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AASP is calculated for the Combined Cycle Train considering all UDSPs to any Combined Cycle Generation Resources within the Combined Cycle Train. | | AVGTG5M *q, r, p, i, y* | MW | *Average Telemetered Generation for the 5 Minutes*—The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*. | | OGEN *q, r, p, i* | MWh | *Over Generation Volumes per QSE per Settlement Point per Resource*—The amount over-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval *i*. | | PR1 | $/MWh | The price to use for the Set Point Deviation Charge for over-generation when RTSPP is less than $20/MWh, $20/MWh. | | K1 | none | The percentage tolerance for over-generation, 5%. | | Q1 | MW | The MW tolerance for over-generation, five MW. | | N | none | The number of IRRs within an IRR Group. | | *Q* | none | A QSE. | | *P* | none | A Settlement Point. | | *R* | none | A non-exempt Generation Resource. | | *y* | none | A five-minute clock interval in the Settlement Interval. | | *i* | none | A 15-minute Settlement Interval. | | *Wg* | none | An IRR Group. | |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR879, NPRR963, and NPRR1010: Replace applicable portions of Section 6.6.5.1.1.2 above with the following upon system implementation for NPRR879 or NPRR963; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]***  **6.6.5.2.1 Set Point Deviation Charge for Under Generation**  (1) ERCOT shall charge a QSE for a Generation Resource, including an IRR awarded Ancillary Service for at least one SCED interval within the 15-minute Settlement Interval, for under-generation if the telemetered generation is below the lesser of:  (a) 95% of the AASP in the Settlement Interval; or  (b) The AASP in the Settlement Interval minus five MW.  (2) For instances in which an IRR is not awarded Ancillary Service or is not part of an IRR Group in which an IRR is awarded Ancillary Service for any SCED interval within the 15-minute Settlement Interval, Set Point Deviation Charges will be determined per Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge.  (3) The under-generation charge to each QSE for each Generation Resource, that is not part of an IRR Group at each Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:  **SPDAMT *q, r, p, i* = -1 \* Min (PR2, RTSPP *p, i*) \* Min (1, KP) \* UGEN *q, r, p, i***  Where:  UGEN *q, r, p, i* = Max [0, [Min ((1- K2) \* ¼\* AASP *q, r, p, i* ,  ¼ \* (AASP *q, r, p, i* - Q2)) - TWTG *q, r, p, i*]]  TWTG *q, r, p, i =* ( (AVGTG5M *q, r, p, i, y*) / 3) \* ¼  (4) If any IRR in an IRR Group is awarded Ancillary Service for at least one SCED interval within the 15-minute Settlement Interval, then the deviation penalty is determined for the IRR Group and evenly allocated and charged to each IRR within that IRR Group as follows:  **SPDAMT *q, r, p, i*  = -1 \* Min (PR2, RTSPP *p, i*) \* Min (1, KP) \* UGEN *q, r, p, i***  Where:  UGEN *q, r, p, i*  = Max [0, [Min ((1 - K2) \* ¼\* AASP *q, wg, p, i* ,  ¼ \* (AASP *q, wg, p, i* - Q2)) - TWTG *q, wg, p, i*]] / N  TWTG *q, wg, p, i* = ( (AVGTG5M *q, r, p, i, y*) / 3) \* ¼  AASP *q, wg, p, i* = (AASP *q, r, p, i*)  The above variables are defined as follows:   |  |  |  | | --- | --- | --- | | **Variable** | **Unit** | **Definition** | | SPDAMT *q, r, p, i* | $ | *Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval *i*. A Set Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources. | | RTSPP *p, i* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*. | | TWTG *q, r, p, i* | MWh | *Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | AASP*q, r, p, i* | MW | *Average Aggregated Set Point*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Generation Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AASP is calculated for the Combined Cycle Train considering all UDSPs to any Combined Cycle Generation Resources within the Combined Cycle Train. | | AVGTG5M *q, r, p, i, y* | MW | *Average Telemetered Generation for the 5 Minutes* —The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the five-minute clock interval *y*, within the 15-minute Settlement Interval *i*. | | UGEN *q, r, p, i* | MWh | *Under-Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval *i*. | | KP | none | The coefficient applied to the Settlement Point Price for under-generation charge, 1.0. | | PR2 | $/MWh | The price to use for the Set Point Deviation Charge for under-generation calculation when RTSPP is greater than -$20/MWh, -$20/MWh. | | K2 | none | The percentage tolerance for under-generation, 5%. | | Q2 | MW | The MW tolerance for under-generation, five MW. | | N | none | The number of IRRs within an IRR Group. | | *q* | none | A QSE. | | *p* | none | A Settlement Point. | | *r* | none | A non-exempt Generation Resource. | | *y* | none | A five-minute clock interval in the Settlement Interval. | | *i* | none | A 15-minute Settlement Interval. | | *wg* | none | An IRR Group. | |

**6.6.5.4 Base Point Deviation Payment**

(1) ERCOT shall pay the Base Point Deviation Charges collected from the QSEs representing Resources to the QSEs representing Load based on LRS. The payment to each QSE for a given 15-minute Settlement Interval is calculated as follows:

**LABPDAMT *q* = (-1) \* BPDAMTTOT \* LRS *q***

Where:

BPDAMTTOT = BPDAMTQSETOT *q*

BPDAMTQSETOT *q* = BPDAMT *q, r, p*

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| LABPDAMT *q* | $ | *Load-Allocated Base Point Deviation Amount per QSE*—QSE *q*’s share of the total charge for all Resources’ Base Point deviations, based on LRS for the 15-minute Settlement Interval. |
| BPDAMTTOT | $ | *Base Point Deviation Amount Total*—The total of Base Point Deviation Charges to all QSEs for all Resources, for the 15-minute Settlement Interval. |
| BPDAMTQSETOT *q* | $ | *Base Point Deviation Amount QSE Total per QSE*—The total of Base Point Deviation Charges to QSE *q* for all Resources represented by this QSE, for the 15-minute Settlement Interval. |
| BPDAMT *q, r, p* | $ | *Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource or Controllable Load Resource *r* at Settlement Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval. A Base Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources. |
| LRS *q* | none | The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval. |
| *q* | none | A QSE. |
| *p* | none | A Settlement Point. |
| *r* | none | A Generation Resource or Controllable Load Resource. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1010: Replace Section 6.6.5.4 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  **6.6.5.4 Set Point Deviation Payment**  (1) ERCOT shall pay the Set Point Deviation Charges collected from the QSEs representing Resources to the QSEs representing Load based on LRS. The payment to each QSE for a given 15-minute Settlement Interval is calculated as follows:  **LASPDAMT *q* = (-1) \* SPDAMTTOT \* LRS *q***  Where:  SPDAMTTOT = SPDAMTQSETOT *q*  SPDAMTQSETOT *q* = SPDAMT *q, r, p*  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | LASPDAMT *q* | $ | *Load-Allocated Set Point Deviation Amount per QSE*—QSE *q*’s share of the total charge for all Resources’ Set Point deviations, based on LRS for the 15-minute Settlement Interval. | | SPDAMTTOT | $ | *Set Point Deviation Amount Total*—The total of Set Point Deviation Charges to all QSEs for all Resources, for the 15-minute Settlement Interval. | | SPDAMTQSETOT *q* | $ | *Set Point Deviation Amount QSE Total per QSE*—The total of Set Point Deviation Charges to QSE *q* for all Resources represented by this QSE, for the 15-minute Settlement Interval. | | SPDAMT *q, r, p* | $ | *Set Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Resource *r* at Settlement Node *p*, for its deviation from AASP, for the 15-minute Settlement Interval. A Set Point Deviation Charge is charged to the Combined Cycle Train for all Combined Cycle Generation Resources. | | LRS *q* | none | The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval. | | *q* | none | A QSE. | | *p* | none | A Settlement Point. | | *r* | none | A Generation Resource, ESR, or Controllable Load Resource. | |

**6.6.7.1 Voltage Support Service Payments**

(1) All other Generation Resources shall be eligible for compensation for Reactive Power production in accordance with Section 6.5.7.7, Voltage Support Service, only if ERCOT issues a Dispatch Instruction that results in the following unit operation:

(a) When ERCOT instructs the Generation Resource to exceed its Unit Reactive Limit (URL) and the Generation Resource provides additional Reactive Power, then ERCOT shall pay for the additional Reactive Power provided at a price that recognizes the avoided cost of reactive support to Resources on the transmission network.

(b) Any real power reduction directed by ERCOT through VDIs to provide for additional reactive capability for voltage support must be compensated as a lost opportunity payment.

(2) The payment for a given 15-minute Settlement Interval to each QSE representing a Generation Resource that operates in accordance with an ERCOT Dispatch Instruction is calculated as follows:

Depending on the Dispatch Instruction, payment for Volt-Amperes reactive (VAr):

If VSSVARLAG *q, r* > 0

**VSSVARAMT *q, r* = (-1) \* VSSVARPR \* VSSVARLAG *q, r***

If VSSVARLEAD *q, r* > 0

**VSSVARAMT *q, r* = (-1) \* VSSVARPR \* VSSVARLEAD *q, r***

Where:

VSSVARLAG *q, r* = Max [0, Min (¼ \* VSSVARIOL *q, r*, RTVAR *q, r*) – (¼ \* URLLAG *q, r*)]

VSSVARLEAD *q, r* = Max {0, [(¼ \* URLLEAD *q, r* ) – Max ((¼ \* VSSVARIOL *q, r*), RTVAR *q, r*)]}

URLLAG *q,r* = 0.32868 \* HSL *q,r*

URLLEAD *q,r* = (-1) \* 0.32868 \* HSL *q,r*

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| VSSVARAMT *q, r* | $ | *Voltage Support Service VAr Amount per QSE per Generation Resource -* The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| VSSVARPR | $/MVArh | *Voltage Support Service VAr Price -* The price for instructed MVAr beyond a Generation Resource’s URL currently is $2.65/MVArh (based on $50.00/installed kVAr). |
| VSSVARLAG *q, r* | MVArh | *Voltage Support Service VAr Lagging per QSE per Generation Resource -* The instructed portion of the Reactive Power above the Generation Resource’s lagging URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| VSSVARLEAD *q, r* | MVArh | *Voltage Support Service VAr Leading per QSE per Generation Resource* - The instructed portion of the Reactive Power below the Generation Resource’s leading URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| VSSVARIOL *q, r* | MVAr | *Voltage Support Service VAr Instructed Output Level per QSE per Generation Resource*—The instructed Reactive Power output level of Generation Resource *r* represented by QSE *q*, lagging Reactive Power if positive and leading Reactive Power if negative, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| RTVAR *q, r* | MVArh | *Real-Time VAr per QSE per Resource*—The netted Reactive Energy measured for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| URLLAG *q, r* | MVAr | *Unit Reactive Limit Lagging per QSE per Resource*—The URL for lagging Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is positive. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| URLLEAD *q, r* | MVAr | *Unit Reactive Limit Leading per QSE per Resource*—The URL for leading Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is negative. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| HSL *q, r* | MW | *High Sustained Limit*—The HSL of a Generation Resource as defined in Section 2, Definitions and Acronyms, for the hour that includes the Settlement Interval *i*. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource. |
| *q* | none | A QSE. |
| *r* | none | A Generation Resource. |

(3) The total additional compensation to each QSE for VSS for the 15-minute Settlement Interval is calculated as follows:

**VSSVARAMTQSETOTq =**  **VSSVARAMT***q,r*

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| VSSVARAMT *q, r* | $ | *Voltage Support Service VAr Amount per QSE per Generation Resource*—The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| VSSVARAMTQSETOT *q* | $ | *Voltage Support VAr Amount QSE total per QSE*—The total of the payments to QSE *q* as compensation for VSS by this QSE for the 15-minute Settlement Interval. |
| *q* | none | A QSE. |
| *r* | none | A Generation Resource. |

(4) The lost opportunity payment, if applicable:

**VSSEAMT *q, r* = (-1) \* Max (0, (RTSPP*p* – RTEOCOST *q, r, i*) \* Max (0, (HSL *q, r* \* ¼ - RTMG *q, r*)))**

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| VSSEAMT *q, r* | $ | *Voltage Support Service Energy Amount per QSE per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource *r* for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| RTMG *q, r* | MWh | *Real-Time Metered Generation per QSE per Resource*—The Real-Time metered generation of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| RTSPP *p* | $/MWh | *Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource Node for the 15-minute Settlement Interval. |
| RTEOCOST *q, r, i* | $/MWh | *Real-Time Energy Offer Curve Cost*—The Energy Offer Curve Cost for Resource *r* represented by QSE *q*, for the Resource’s generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Costs. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| HSL *q, r* | MW | *High Sustained Limit Generation per QSE per Settlement Point per Resource*—The HSL of Generation Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource. |
| LSL *q, r* | MW | *Low Sustained Limit Generation per QSE per Settlement Point per Resource*—The LSL of Generation Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource. |
| *q* | none | A QSE. |
| *r* | none | A Generation Resource. |
| *p* | none | A Resource Node Settlement Point. |

(5) The total of the payments to each QSE for ERCOT-directed power reduction to provide VSS for a given 15-minute Settlement Interval is calculated as follows:

**VSSEAMTQSETOT *q* = VSSEAMT *q****, r*

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| VSSEAMTQSETOT *q* | $ | *Voltage Support Service Lost Opportunity Amount QSE Total per QSE*⎯The total of the lost opportunity payments to QSE *q* for providing VSS for providing ERCOT-directed VSS for the 15-minute Settlement Interval. |
| VSSEAMT *q, r* | $ | *Voltage Support Service Energy Amount per QSE per Settlement Point per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource *r* for the 15-minute Settlement Interval for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. |
| *q* | none | A QSE. |
| *r* | none | A Generation Resource. |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR1014: Replace Section 6.6.7.1 above with the following upon system implementation:]***  **6.6.7.1 Voltage Support Service Payments**  (1) All other Generation Resources or ESRs shall be eligible for compensation for Reactive Power production in accordance with Section 6.5.7.7, Voltage Support Service, only if ERCOT issues a Dispatch Instruction that results in the following unit operation:  (a) When ERCOT instructs the Generation Resource or ESR to exceed its Unit Reactive Limit (URL) and the Generation Resource or ESR provides additional Reactive Power, then ERCOT shall pay for the additional Reactive Power provided at a price that recognizes the avoided cost of reactive support to Resources on the transmission network.  (b) Any real power reduction directed by ERCOT through VDIs to provide for additional reactive capability for voltage support must be compensated as a lost opportunity payment.  (2) An ESR with a net injection for a Settlement Interval but that has a High Sustained Limit (HSL) that is less than zero will not receive compensation for Reactive Power for that Settlement Interval.  (3) The payment for a given 15-minute Settlement Interval to each QSE representing a Generation Resource or ESR that operates in accordance with an ERCOT Dispatch Instruction is calculated as follows:  Depending on the Dispatch Instruction, payment for Volt-Amperes reactive (VAr):  If VSSVARLAG *q, r* > 0  **VSSVARAMT *q, r* = (-1) \* VSSVARPR \* VSSVARLAG *q, r***  If VSSVARLEAD *q, r* > 0  **VSSVARAMT *q, r* = (-1) \* VSSVARPR \* VSSVARLEAD *q, r***  Where:  VSSVARLAG *q, r* = Max [0, Min (¼ \* VSSVARIOL *q, r*, RTVAR *q, r*) – (¼ \* URLLAG *q, r*)]  VSSVARLEAD *q, r* = Max {0, [(¼ \* URLLEAD *q, r* ) – Max ((¼ \* VSSVARIOL *q, r*), RTVAR *q, r*)]}  And:  If an ESR has a net withdrawal for the Settlement Interval, then:  URLLAG *q,r* = 0.32868 \* ABS(LSL *q,r*)  URLLEAD *q,r* = (-1) \* 0.32868 \* ABS(LSL *q,r*)  Otherwise, for Generation Resources or ESRs that have a net injection for the Settlement Interval and that have an HSL greater than or equal to 0:  URLLAG *q,r* = 0.32868 \* HSL *q,r*  URLLEAD *q,r* = (-1) \* 0.32868 \* HSL *q,r*  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | VSSVARAMT *q, r* | $ | *Voltage Support Service VAr Amount per QSE per Resource -* The payment to QSE *q* for the VSS provided by Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | VSSVARPR | $/MVArh | *Voltage Support Service VAr Price -* The price for instructed MVAr beyond a Resource’s URL currently is $2.65/MVArh (based on $50.00/installed kVAr). | | VSSVARLAG *q, r* | MVArh | *Voltage Support Service VAr Lagging per QSE per Resource -* The instructed portion of the Reactive Power above the Resource’s lagging URL for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | VSSVARLEAD *q, r* | MVArh | *Voltage Support Service VAr Leading per QSE per Resource* - The instructed portion of the Reactive Power below the Resource’s leading URL for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | VSSVARIOL *q, r* | MVAr | *Voltage Support Service VAr Instructed Output Level per QSE per Resource*—The instructed Reactive Power output level of Resource *r* represented by QSE *q*, lagging Reactive Power if positive and leading Reactive Power if negative, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | RTVAR *q, r* | MVArh | *Real-Time VAr per QSE per Resource*—The netted Reactive Energy measured for Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | URLLAG *q, r* | MVAr | *Unit Reactive Limit Lagging per QSE per Resource*—The URL for lagging Reactive Power of the Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is positive. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | URLLEAD *q, r* | MVAr | *Unit Reactive Limit Leading per QSE per Resource*—The URL for leading Reactive Power of the Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is negative. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | HSL *q, r* | MW | *High Sustained Limit*—The HSL of Resource *r* represented by QSE *q* as defined in Section 2, Definitions and Acronyms, for the hour that includes the Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource. | | LSL *q, r* | MW | *Low Sustained Limit*—The LSL for Resource *r* represented by QSE *q*, as defined in Section 2, for the hour that includes the Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource. | | *q* | none | A QSE. | | *r* | none | A Generation Resource or ESR. |   (4) The total additional compensation to each QSE for voltage support service for the 15-minute Settlement Interval is calculated as follows:  **VSSVARAMTQSETOTq =**  **VSSVARAMT***q,r*   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | VSSVARAMT *q, r* | $ | *Voltage Support Service VAr Amount per QSE per Resource*—The payment to QSE *q* for the VSS provided by Resource *r*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | VSSVARAMTQSETOT *q* | $ | *Voltage Support VAr Amount QSE total per QSE*—The total of the payments to QSE *q* as compensation for VSS by this QSE for the 15-minute settlement interval. | | *q* | None | A QSE. | | *r* | None | A Generation Resource or ESR. |   (5) The lost opportunity payment, if applicable:  If an ESR has a net withdrawal for the Settlement Interval, then:  **VSSEAMT *q, r* = (-1) \* Max (0, RTSPP*p* ) \* Max (0, (ABS(LSL *q, r* \* ¼ - NETVSSA *q, r*)))**  Otherwise, for Generation Resources or ESRs that have a net injection for the Settlement Interval:  **VSSEAMT *q, r* = (-1) \* Max (0, (RTSPP*p* – RTEOCOST *q, r, i*) \* Max (0, (HSL *q, r* \* ¼ - NETVSSA *q, r*)))**  Where:  NETVSSA *q, r* = RTCL *q, r +* RTMG *q, r*  For an ESR that is not a WSL:  RTCL *q, r* =  MEBR *q, r, b*  And for an ESR that is a WSL:  RTCL *q, r* =  MEBL *q, r, b*  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | VSSEAMT *q, r* | $ | *Voltage Support Service Energy Amount per QSE per Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Resource *r* for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | RTMG *q, r* | MWh | *Real-Time Metered Generation per QSE per Resource*—The Real-Time metered generation of Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | RTSPP *p* | $/MWh | *Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource Node for the 15-minute Settlement Interval. | | RTEOCOST *q, r, i* | $/MWh | Real-Time Energy Offer Curve Cost - The Energy Offer Curve Cost for Resource *r* represented by QSE *q*, for the Resource’s generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Costs. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | |  | | | | NETVSSA *q, r* | MWh | *Net VSS Activity*—The sum of the total energy metered by the Settlement Meter which measures ESR load and the RTMG, for Resource *r* represented by the QSE *q* for the 15-minute Settlement Interval. | | RTCL *q, r* | MWh | *Real-Time Charging Load per QSE per Resource* —The charging load for Resource *r* represented by the QSE *q*, represented as a negative value,for the 15-minute Settlement Interval. | | MEBL *q, r, b* | MWh | *Metered Energy for Wholesale Storage Load at Bus*⎯The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | MEBR *q, r, b* | MWh | *Metered Energy for Energy Storage Resource load at Bus* - The energy metered by the Settlement Meter which measures ESR load that is not WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | HSL *q, r* | MW | *High Sustained Limit per QSE per Settlement Point per Resource*—The HSL of Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource. | | LSL *q, r* | MW | *Low Sustained Limit per QSE per Settlement Point per Resource*—The LSL of Resource *r* represented by QSE *q* at Resource Node *p* for the hour that includes the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Generation Resource. | | *q* | none | A QSE. | | *r* | none | A Generation Resource or ESR. | | *p* | none | A Resource Node Settlement Point. | | *b* | none | An Electrical Bus. |   (6) The total of the payments to each QSE for ERCOT-directed power reduction to provide VSS for a given 15-minute Settlement Interval is calculated as follows:  **VSSEAMTQSETOT *q* =** **VSSEAMT *q, r***  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | VSSEAMTQSETOT *q* | $ | *Voltage Support Service Lost Opportunity Amount QSE Total per QSE*⎯The total of the lost opportunity payments to QSE *q* for providing VSS for providing ERCOT-directed VSS for the 15-minute Settlement Interval. | | VSSEAMT *q, r* | $ | *Voltage Support Service Energy Amount per QSE per Settlement Point per Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Resource *r* for the 15-minute Settlement Interval for the 15-minute Settlement Interval. Where for a combined cycle resource, *r* is a Combined Cycle Train. | | *q* | none | A QSE. | | *r* | none | A Generation Resource or ESR. | |

***6.6.9 Emergency Operations Settlement***

(1) Due to Emergency Conditions or Watches, additional compensation for each Generation Resource for which ERCOT provides an Emergency Base Point may be awarded to the QSE representing the Generation Resource. If the Emergency Base Point is higher than the SCED Base Point immediately before the Emergency Condition or Watch and the Settlement Point Price at the Resource Node is lower than the Generation Resource’s Energy Offer Curve price at the Emergency Base Point, ERCOT shall pay the QSE additional compensation for the additional energy above the SCED Base Point.

(2) In accordance with paragraph (8) of Section 8.1.1.2, General Capacity Testing Requirements, QSEs that receive a VDI to operate the designated Generation Resource for an unannounced Generation Resource test may be considered for additional compensation utilizing the formula as stated in Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT. If the test period SCED Base Point is higher than the SCED Base Point immediately before the test period and the Settlement Point Price at the Resource Node is lower than the Generation Resource’s Energy Offer Curve price, or MOC if no offer exists, at the test Base Point, and the test was not a retest requested by the QSE, ERCOT shall pay the QSE additional compensation for the additional energy above the pre-test SCED Base Point. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the unannounced Generation Resource test, SCED Base Points will be used in place of the Emergency Base Point.

(3) A QSE that represents a QSGR that comes On-Line as a result of a Base Point greater than zero shall be considered for additional compensation using the formula in Section 6.6.9.1 when the Base Point is less than or equal to its applicable Seasonal net minimum sustainable rating provided in the Resource Registration data. If the Resource Settlement Point Price at the QSGR’s Resource Node is lower than the Energy Offer Curve price, capped per the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap, at the aggregated Base Point during the 15-minute Settlement Interval, ERCOT shall pay the QSE additional compensation for the amount of energy from the Off-Line zero Base Point to the aggregated output level. For the purpose of this Settlement, inclusive of the first Settlement Interval in which the QSGR is deployed by SCED from a current SCED Base Point equal to zero MW to a Base Point greater than zero, SCED Base Points will be used in place of the Emergency Base Point. The compensation specified in this paragraph continues over all applicable Intervals until SCED no longer needs the QSGR to generate energy pursuant to Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process, and there is no manual Low Dispatch Limit (LDL) override in place on the QSGR.

(4) QSEs that received Base Points that are inconsistent with Real-Time Settlement Point Prices and QSEs that receive a manual override from the ERCOT Operator shall be considered for additional compensation using the formula in Section 6.6.9.1. If the Resource Settlement Point Price at the Resource Node is lower than the Energy Offer Curve price, capped per the MOC pursuant to Section 4.4.9.4.1, at the held Base Point during the 15-minute Settlement Interval, ERCOT shall pay the QSE additional compensation for the amount of energy from a zero Base Point to the held Base Point. The held Base Point is the Base Point that the QSE received due to a manual override by ERCOT Operator or the Base Point received by the QSE that ERCOT identified as inconsistent with Real-Time Settlement Point Prices. For the purpose of this Settlement, and limited to the held Settlement Intervals inclusive of the manual override or Base Points identified as inconsistent with prices, SCED Base Points will be used in place of the Emergency Base Point.

(5) In accordance with Section 6.3, Adjustment Period and Real-Time Operations Timeline, if ERCOT sets any SCED interval as failed, then QSEs shall be considered for additional compensation using the formula in Section 6.6.9.1. For the purpose of this Settlement, and limited to the failed SCED interval, SCED Base Points will be used in place of the Emergency Base Point.

(6) For each 15-minute Settlement Interval, a QSGR that receives a manual override from the ERCOT Operator shall only be considered for compensation under paragraph (4) above.

(7) For a QSGR, the MOC curve used to cap the Energy Offer Curve shall not include the variable Operations and Maintenance (O&M) adjustment cost to start the Resource from first fire to LSL, including the startup fuel described in paragraph (1)(c) of Section 4.4.9.4.1 for all emergency operations Settlement calculations with the exception of paragraph (3) above.

(8) QSEs that receive a VDI to operate its Resources for an unannounced CFC test, as described in the ERCOT Operating Guides, or have been instructed to operate in CFC mode, may be considered for additional compensation utilizing the formula in Section 6.6.9.1. If the Resource Settlement Point Price at the Resource Node is lower than the Energy Offer Curve price, capped per the MOC pursuant to Section 4.4.9.4.1, at the Emergency Base Point during the CFC period, ERCOT shall pay the QSE additional compensation for the amount of energy from a zero Base Point to the Emergency Base Point for each Resource that provided CFC. Compensation for a CFC test will not be provided if the test was a retest requested by the QSE. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the CFC period, the Emergency Base Point shall be set to the Average Telemetered Generation for the 5 Minutes (AVGTG5M). Only Resources that moved in the direction to correct frequency are eligible to receive compensation for providing CFC.

(9) If Emergency Base Points or SCED Base Points are unavailable, corrupted or otherwise unusable for Settlement purposes due to system conditions, hardware failure, or software failure, the Real-Time Metered Generation (RTMG) will be used to create proxy Base Points pursuant to Section 6.6.9.1. If the RTMG is not available the most accurate available generation data as determined by ERCOT will be used to create proxy Base Points pursuant to Section 6.6.9.1. ERCOT shall issue a Market Notice stating the Operating Day and Settlement Intervals that were impacted and the generation data that was used to create proxy Base Points.

|  |
| --- |
| [NPRR1010 and NPRR1014: Replace applicable portions of Section 6.6.9 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]  ***6.6.9 Emergency Operations Settlement***  (1) Due to Emergency Conditions or Watches, additional compensation for each Generation Resource or Energy Storage Resource (ESR) for which ERCOT provides an Emergency Base Point may be awarded to the QSE representing the Generation Resource or ESR. If the Resource was instructed to increase generation at a Settlement Point price that is lower than the price based on their Energy Offer Curve or Energy Bid/Offer Curve, or if the Resource was instructed to increase withdrawal at a Settlement Point price that is higher than the price based on their Energy Bid/Offer Curve, ERCOT shall pay the QSE additional compensation for the change from the SCED Base Point immediately before the Emergency Condition or Watch, per paragraph (1) in Section 6.6.9.1, Payment for Emergency Operations Settlement. The Energy Offer Curve and Energy/Bid Offer Curve shall be capped by the Mitigated Offer Cap (MOC).  (2) In accordance with paragraph (8) of Section 8.1.1.2, General Capacity Testing Requirements, QSEs that receive a VDI to operate the designated Generation Resource for an unannounced Generation Resource test may be considered for additional compensation utilizing the formula as stated in paragraph (1) in Section 6.6.9.1. If the test period SCED Base Point is higher than the SCED Base Point immediately before the test period and the Settlement Point Price at the Resource Node is lower than the Generation Resource’s Energy Offer Curve price, or MOC if no offer exists, at the test Base Point, and the test was not a retest requested by the QSE, ERCOT shall pay the QSE additional compensation for the additional energy above the pre-test SCED Base Point. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the unannounced Generation Resource test, SCED Base Points will be used in place of the Emergency Base Point.  (3) A QSE that represents a QSGR that comes On-Line as a result of a Base Point greater than zero shall be considered for additional compensation using the formula in paragraph (2) in Section 6.6.9.1 when the Base Point is less than or equal to its applicable Seasonal net minimum sustainable rating provided in the Resource Registration data. For the 15-minute Settlement Interval, the process for additional compensation compares the Resource’s energy and Ancillary Services revenue with the Resource’s revenue target, as defined in Section 6.6.9.1, considering both Ancillary Service awards and Base Points, where the Energy Offer Curve is capped per the MOC. For the purpose of this Settlement, inclusive of the first Settlement Interval in which the QSGR is deployed by SCED from a current SCED Base Point equal to zero MW to a Base Point greater than zero, SCED Base Points will be used in place of the Emergency Base Point. The compensation specified in this paragraph continues over all applicable Intervals until SCED no longer needs the QSGR to generate energy pursuant to Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process, and there is no manual Low Dispatch Limit (LDL) override in place on the QSGR.  (4) QSEs that received Base Points that are inconsistent with Real-Time Settlement Point Prices and QSEs that receive a manual override from the ERCOT Operator shall be considered for additional compensation using the formula in paragraph (2) in Section 6.6.9.1. For the 15-minute Settlement Interval, the process for additional compensation compares the Resource’s energy and Ancillary Services revenue with the Resource’s revenue target, as defined in Section 6.6.9.1, considering both the Ancillary Service awards and held Base Points, where the Energy Offer Curve or the Energy Bid/Offer Curve is capped per the MOC. The held Base Point is the Base Point that the QSE received due to a manual override by ERCOT Operator or the Base Point received by the QSE that ERCOT identified as inconsistent with Real-Time Settlement Point Prices. For the purpose of this Settlement, and limited to the held Settlement Intervals inclusive of the manual override or Base Points identified as inconsistent with prices, SCED Base Points will be used in place of the Emergency Base Point.  (5) In accordance with Section 6.3, Adjustment Period and Real-Time Operations Timeline, if ERCOT sets any SCED interval as failed, then QSEs shall be considered for additional compensation using the formula in paragraph (1) in Section 6.6.9.1. For the purpose of this Settlement, and limited to the failed SCED interval, SCED Base Points will be used in place of the Emergency Base Point.  (6) For each 15-minute Settlement Interval, a QSGR that receives a manual override from the ERCOT Operator shall only be considered for compensation under paragraph (4) above.  (7) For a QSGR, the MOC curve used to cap the Energy Offer Curve shall not include the variable Operations and Maintenance (O&M) adjustment cost to start the Resource from first fire to LSL, including the startup fuel described in paragraph (1)(d) of Section 4.4.9.4.1 for all emergency operations Settlement calculations with the exception of paragraph (3) above.  (8) Any QSE that receives a VDI to operate its Resource for an unannounced CFC test, as described in the ERCOT Operating Guides, or that has been instructed to operate in CFC mode, may be considered for additional compensation utilizing the formula in paragraph (1) in Section 6.6.9.1. If the Resource increased generation at a Settlement Point Price that is lower than the price based on the Energy Offer Curve or Energy Bid/Offer Curve, or if the Resource was instructed to increase withdrawal at a Settlement Point Price that is higher than the price based on its Energy Bid/Offer Curve, ERCOT shall pay the QSE additional compensation for the amount of energy from a zero Base Point to the Emergency Base Point for each Resource that provided CFC. Compensation for a CFC test will not be provided if the test was a retest requested by the QSE. For the purpose of this Settlement, and limited to Settlement Intervals inclusive of the CFC period, the Emergency Base Point shall be set to the Average Telemetered Generation for the 5 Minutes (AVGTG5M) and the Energy Offer Curve and Energy/Bid Offer Curve shall be capped by the MOC. Only Resources that moved in the direction to correct frequency are eligible to receive compensation for providing CFC.  (9) If Emergency Base Points or SCED Base Points are unavailable, corrupted or otherwise unusable for Settlement purposes due to system conditions, hardware failure, or software failure, the Real-Time Metered Generation (RTMG) and Real-Time Charging Load (RTCL) will be used to create proxy Base Points pursuant to Section 6.6.9.1. If the RTMG and RTCL are not available, the most accurate available generation and withdrawal data as determined by ERCOT will be used to create proxy Base Points pursuant to Section 6.6.9.1. ERCOT shall issue a Market Notice stating the Operating Day and Settlement Intervals that were impacted and the data that was used to create proxy Base Points.  (10) The Energy Offer Curve or Energy Bid/Offer Curve used to calculate the Emergency Base Point Price (EBPPR) will be the Energy Offer Curve or Energy Bid/Offer Curve that was submitted by the QSE and effective for the applicable Operating Hour at the time of the triggering event that led to emergency Settlement consideration, except when the QSE has received Base Points that are inconsistent with Real-Time Settlement Point Prices, as described in paragraph (4) above. In the case of the condition described in paragraph (3) above, the triggering event would be the first interval in which the QSGR comes On-Line as a result of a Base Point greater than zero.  (11) For ESRs that qualify for emergency Settlement, for purposes of this section, the MOC curve used to cap the Energy Bid/Offer Curve shall be set to the highest Real-Time Settlement Point Price (RTSPP) at the Resource’s Settlement Point for the Operating Day. |

**8.1 QSE and Resource Performance Monitoring**

(1) ERCOT shall develop a Technical Advisory Committee (TAC)- and ERCOT Board-approved Qualified Scheduling Entity (QSE) and Resource monitoring program to be included in the Operating Guides. Nothing in this Section changes the process for amending the Operating Guides. The metrics developed by ERCOT and approved by TAC and the ERCOT Board must include the provisions of this Section.

(2) Each QSE and Resource shall meet performance measures as described in this Section and in the Operating Guides.

(3) ERCOT shall monitor and post the following categories of performance:

(a) Real-Time data, for QSEs:

(i) Telemetry performance

(b) Regulation control performance, for QSEs and as applicable, Resource-specific performance (see also Section 8.1.1, QSE Ancillary Service Performance Standards);

(c) Hydro responsive testing for Generation Resources;

(d) Supplying and validating data for generator models, as requested by ERCOT, for Generation Resources and Energy Storage Resources (ESRs);

(e) Outage scheduling and coordination, for QSEs and Resources;

(f) Resource-specific Responsive Reserve (RRS) performance for QSEs and Resources;

(g) Resource-specific Non-Spinning Reserve (Non-Spin) performance, for QSEs and Resources;

(h) Resource-specific ERCOT Contingency Reserve Service (ECRS) performance for QSEs and Resources;

(i) Outage reporting, by QSEs for Resources;

(j) Current Operating Plan (COP) metrics, for QSEs; and

(k) Day-Ahead Reliability Unit Commitment (DRUC) and Hourly Reliability Unit Commitment (HRUC) commitment performance by QSEs and Generation Resources.

8.1.1.1 Ancillary Service Qualification and Testing

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

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

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

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

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

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

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

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

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

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

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

(b) The requested MW deployment.

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

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

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

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

(b) The MW deployment.

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

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

|  |
| --- |
| [NPRR963, NPRR1011, and NPRR1188: Replace applicable portions of Section 8.1.1.1 above with the following upon system implementation for NPRR963 or NPRR1188; or upon system implementation of Real-Time Co-Optimization (RTC) project for NPRR1011:]  **8.1.1.1 Ancillary Service Qualification and Testing**  (1) Each QSE and the Resource providing Ancillary Service must meet qualification criteria to operate satisfactorily with ERCOT. ERCOT shall use the Ancillary Service qualification and testing program that is approved by TAC and included in the Operating Guides. Each QSE for the Resources that it represents may only provide Ancillary Services on those Resources for which it has met the qualification criteria.  (2) General capacity testing must be used to verify a Resource’s Net Dependable Capability. Qualification tests allow the Resource and QSE to demonstrate the minimum capabilities necessary to deploy an Ancillary Service.  (3) A Resource may be provisionally qualified for a period of 90 days and may be eligible to participate as a Resource providing Ancillary Service. Resources that have installed the appropriate equipment with verifiable testing data may be provisionally qualified as providers of Ancillary Service.  (4) A Load Resource may be provisionally qualified for a period of 90 days to participate as a Resource providing Ancillary Service, if the Load Resource is metered with an Interval Data Recorder (IDR) to ERCOT’s reasonable satisfaction. A Load Resource providing Ancillary Service in Real-Time must meet the following requirements:  (a) Electric Service Identifier (ESI ID) registration of Load Resources providing Ancillary Service by the QSE; and  (b) Load Resource telemetry is installed and tested between QSE and ERCOT.  (5) Provisional qualification as described herein may be revoked by ERCOT at any time for any non-compliance with provisional qualification requirements.  (6) For those Settlement Intervals during which a Generation Resource, Load Resource, or Energy Storage Resource (ESR) behind the Resource Node is engaged in testing in accordance with this Section, the provisions of Section 6.6.5, Set Point Deviation Charge, will not apply to the Resource being tested beginning with the Settlement Interval immediately preceding the Settlement Interval in which ERCOT issues a Dispatch Instruction that begins the test and continuing until the end of the Settlement Interval in which the test completes. During the same Settlement Intervals for the testing period, the Generation Resource Energy Deployment Performance (GREDP), Controllable Load Resource Energy Deployment Performance (CLREDP), or Energy Storage Resource Energy Deployment Performance (ESREDP) calculated in accordance with Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics, will not apply.  (7) ERCOT may reduce the amount a Resource may contribute toward Ancillary Service if it determines unsatisfactory performance of the Resource as defined in Section 8.1.1, QSE Ancillary Service Performance Standards.  (8) To maintain qualification with ERCOT to provide RRS or ECRS service, each Load Resource, excluding Controllable Load Resources (CLRs), will be subject to a Load interruption test at a date and time determined by ERCOT and known only to ERCOT and the affected Transmission Service Provider (TSP), to verify the ability to respond to an ERCOT Dispatch Instruction. To successfully pass this test, within ten minutes of the receipt of the ERCOT Dispatch Instruction by the Load Resource’s QSE, the Load Resource’s response shall not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:  (a) The Resource’s ECRS and RRS awards, or  (b) The requested MW deployment.  The requested MW deployment will be the sum of the Resource’s ECRS and RRS awards, and the telemetered additional capacity between the net power consumption and the Low Power Consumption (LPC). If a Load Resource has responded to an actual ERCOT Dispatch Instruction in compliance with (a) and (b) above in the rolling 365-day period, ERCOT will use that response in lieu of a Load interruption test. If a Load Resource has not responded to an ERCOT Dispatch Instruction in compliance with (a) and (b) above, either in a deployment event or a Load interruption test, in any rolling 365-day period, it is subject to a Load interruption test by ERCOT. QSEs may request to have individual Load Resources aggregated for the purposes of Load interruption tests. All performance evaluations will apply on an individual Resource basis.  (9) ERCOT may revoke the Ancillary Service qualification of any Load Resource, excluding CLRs, for failure to comply with the required performance standards, based on the evaluation it performed under paragraph (5) of Section 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria or under paragraph (1)(c) of Section 8.1.1.4.4, ERCOT Contingency Reserve Service Energy Deployment Criteria. Specifically, if a Load Resource that is providing RRS or ECRS fails to respond with at least 95% of its ECRS or RRS award within ten minutes of an ERCOT Dispatch Instruction, that response shall be considered a failure. Two Load Resource performance failures, either in a deployment event or a Load interruption test, within any rolling 365-day period shall result in disqualification of that Load Resource. After six months of disqualification, the Load Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Load Resource successfully passes a new Load interruption test as specified in this Section 8.1.1.1.  (10) To maintain qualification with ERCOT to provide RRS from Fast Frequency Response (FFR), each Resource will be subject to an FFR qualification test at a date and time determined by ERCOT and known only to ERCOT and the affected TSP as applicable, to verify the ability to respond to an ERCOT Dispatch Instruction. To successfully pass this test, within ten minutes of the receipt of the ERCOT Dispatch Instruction by the Resource’s QSE, the Resource’s response shall not be less than 95% of the requested MW deployment, nor more than 105% of the lesser of the following:  (a) The Resource’s RRS award; or  (b) The MW deployment.  The requested MW deployment for Resources capable of FFR will be the sum of the Resource’s RRS award and the additional capacity between the telemetered High Sustained Limit (HSL) and the telemetered Low Sustained Limit (LSL). If a Resource has responded to an actual event in compliance with items (a) and (b) above in the rolling 365-day period, ERCOT will use that response in lieu of an FFR test. If a Resource has not responded to an ERCOT Dispatch Instruction in compliance with items (a) and (b) above, in either a deployment event or an FFR test, in any rolling 365-day period, it is subject to an FFR test by ERCOT. All performance evaluations will apply on an individual Resource basis.  (11) ERCOT may revoke the Ancillary Service qualification of any Resource providing FFR if that Resource has two Resource performance failures, either in a manual deployment event or a frequency triggered event, within any rolling 365-day period. A performance failure is defined as a response less than 95% or more than 105% of the Resource’s RRS award within 15 cycles of a triggering event or within ten minutes of an ERCOT Dispatch Instruction. This shall result in disqualification of that Resource. After six months of disqualification, a Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Resource successfully passes a new test as specified in Section 8.1.1.2.1.2, Responsive Reserve Qualification. |

**8.1.1.2.1.7 ERCOT Contingency Reserve Service Qualification**

(1) ECRS may be provided by:

(a) Unloaded Generation Resources that are On-Line;

(b) Quick Start Generation Resources (QSGRs);

(c) Load Resources that may or may not be controlled by high-set under-frequency relays;

(d) Generation Resources operating in the synchronous condenser fast-response mode; or

(e) Controllable Load Resources.

(2) The amount of ECRS provided by individual Generation Resources and Load Resources is limited to ten times its telemetered emergency ramp rate. Each Resource providing ECRS must be capable of ramping the Resource’s Ancillary Service Resources Responsibility for ECRS within ten minutes of the notice to deploy ECRS, and must be able to maintain the scheduled level of deployment for the period of service commitment. The amount of ECRS on a Generation Resource may be further limited by requirements of the Operating Guides.

(3) A Load Resource must be loaded and capable of unloading the scheduled amount of ECRS within ten minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays with settings as specified by the Operating Guides.

(4) Any QSE providing ECRS shall provide communications equipment to receive ERCOT telemetered control deployments of ECRS.

(5) Load Resources providing ECRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay, if applicable.

(6) Each QSE shall ensure that each Resource is able to meet the Resource’s obligations to provide the Ancillary Service Resource Responsibility. Each Generation Resource and Load Resource providing ECRS must meet additional technical requirements specified in this Section.

(7) A qualification test for each Resource to provide ECRS is conducted during a continuous eight-hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements:

(a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE it is to provide an amount of ECRS from its Resource to be qualified equal to the amount that the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) For Generation Resources desiring qualification to provide ECRS, ERCOT shall send a signal to the Resource’s QSE to deploy ECRS, indicating the MW amount. ERCOT shall monitor the QSEs telemetry of the Resource’s Ancillary Service Schedule for an update within 15 seconds. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.4, ERCOT Contingency Reserve Service Energy Deployment Criteria. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource’s qualification to provide ECRS.

(c) For Controllable Load Resources desiring qualification to provide ECRS, ERCOT shall send a signal to the Resource’s QSE to deploy ECRS, indicating the MW amount. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.4. ERCOT shall evaluate the response of the Controllable Load Resource given the current operating conditions of the system and determine the Controllable Load Resource’s qualification to provide ECRS.

(d) For Load Resources, excluding Controllable Load Resources, desiring qualification to provide ECRS, ERCOT shall deploy ECRS, indicating the MW amount. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.4.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing ECRS and shall provide a copy of the certificate to the QSE and the Resource Entity.

|  |
| --- |
| ***[NPRR1011: Replace Section 8.1.1.2.1.7 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  **8.1.1.2.1.7 ERCOT Contingency Reserve Service Qualification**  (1) ECRS may be provided by:  (a) Unloaded Generation Resources that are On-Line;  (b) Quick Start Generation Resources (QSGRs);  (c) Load Resources that may or may not be controlled by high-set under-frequency relays;  (d) Generation Resources operating in the synchronous condenser fast-response mode;  (e) Controllable Load Resources; or  (f) ESRs.  (2) All Resources qualified to participate in SCED or qualified to telemeter a Resource Status of ONSC are also qualified to provide ECRS when the Resource is On-Line. The amount of ECRS for which the Resource is qualified when On-Line will be limited to the amount of capacity that can be ramped or unloaded within ten minutes. Off-Line ECRS can only be provided by qualified QSGRs.  (3) The amount of ECRS provided by individual Generation Resources and Load Resources is limited to ten times its telemetered emergency ramp rate. Each Resource providing ECRS must be capable of ramping the Resource’s Ancillary Service award for ECRS within ten minutes of the notice to deploy ECRS, and must be able to maintain the awarded level of deployment for at least one hour. The amount of ECRS on a Generation Resource may be further limited by requirements of the Operating Guides.  (4) A Load Resource must be loaded and capable of unloading the awarded amount of ECRS within ten minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays with settings as specified by the Operating Guides.  (5) Any QSE providing ECRS shall provide communications equipment to receive ERCOT telemetered control deployments of ECRS.  (6) Load Resources providing ECRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay, if applicable.  (7) Each QSE shall ensure that each Resource is able to meet the Resource’s obligations to provide the Ancillary Service award. Each Generation Resource and Load Resource providing ECRS when Off-Line as a QSGR with an OFFQS Resource Status, or when not qualified to participate in SCED, must meet additional technical requirements specified in this Section.  (8) A qualification test for each Resource to provide ECRS when Off-Line as a QSGR with an OFFQS Resource Status or as a Load Resource, excluding Controllable Load Resources, is conducted during a continuous eight-hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements:  (a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE it is to provide an amount of ECRS from its Resource to be qualified equal to the amount that the QSE is requesting qualification. The QSE shall acknowledge the start of the test.  (b) Generation Resources desiring qualification to provide ECRS when Off-Line must meet the QSGR qualification criteria outlined under Section 8.1.1.2, General Capacity Testing Requirements. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.2 for QSGR. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource’s qualification to provide ECRS.  (c) For Load Resources, excluding Controllable Load Resources, desiring qualification to provide ECRS, ERCOT shall deploy ECRS, indicating the MW amount. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.4.  (d) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing ECRS and shall provide a copy of the certificate to the QSE and the Resource Entity. |

**8.1.1.4.1 Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics**

(1) ERCOT shall limit the deployment of Regulation Service of each QSE for each LFC cycle equal to 125% of the total amount of Regulation Service in the ERCOT System divided by the number of control cycles in five minutes.

(2) For those Resources that do not have a Resource Status of ONDSR or ONDSRREG or Intermittent Renewable Resource (IRR) Groups with no member IRR having a status of ONDSR or ONDSRREG, ERCOT shall compute the GREDP for each Generation Resource that is On-Line and released to SCED Base Point Dispatch Instructions. The GREDP is calculated for each five-minute clock interval as a percentage and in MWs for those Resources with a Resource Status that is not ONDSR or ONDSRREG as follows:

**GREDP (%) = ABS[((ATG – AEPFR)/(ABP + ARI)) – 1.0] \* 100**

**GREDP (MW) = ABS(ATG – AEPFR – ABP - ARI)**

Where:

ATG = Average Telemetered Generation = the average telemetered generation of the Generation Resource or for the aggregate of the IRRs within an IRR Group for the five-minute clock interval

ARI = Average Regulation Instruction = the amount of regulation that the Generation Resource or IRR Group should have produced based on the LFC deployment signals, calculated by LFC, during each five-minute clock interval

∆frequency is actual frequency minus 60 Hz

EPFR = Estimated Primary Frequency Response (MW) = if │∆frequency│≤ Governor Dead-Band then EPFR = zero, if not then if ∆frequency > zero, EPFR = (∆frequency - Governor Dead-Band)/((droop value \* 60) – Governor Dead-Band) \* HSL \* -1, if not then if ∆frequency < zero, EPFR = (∆frequency + Governor Dead-Band)/((droop value \* 60) – Governor Dead-Band) \* HSL \* -1

AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05 the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval. For Combined Cycle Generation Resources, or Generation Resources that have been approved to telemeter Non-Frequency Responsive Capacity (NFRC), the HSL will be reduced by the telemetered NFRC MW to calculate the EPFR. For Combined Cycle Generation Resources, 5.78% Governor droop shall be used. The Resource-specific calculations will be aggregated for IRR Groups.

ABP = Average Base Point = the time-weighted average of a linearly ramped Base Point or sum of Base Points for IRR Groups, for the five-minute clock interval. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five-minute period. The initial value of the linearly ramped Base Point will be the four-second value of the previous linearly ramped Base Point at the time the new SCED Base Point is received into the ERCOT Energy Management System (EMS). In the event that the SCED Base Point is received after the five-minute ramp period, the linearly ramped Base Point will continue at a constant value equal to the ending four-second value of the five-minute ramp.

(3) For all of a QSE’s Resources that have a Resource Status of ONDSR or ONDSRREG (“Dynamically Scheduled Resource (DSR) Portfolio”), ERCOT shall calculate an aggregate GREDP as a percentage and in MWs for those Resources as follows:

**GREDP (%) = ABS[(∑*DSR* ATG – ∑*DSR*DBPOS + Intra-QSE Purchase – Intra-QSE Sale – ARRDDSRLR – AECRDDSRLR – ANSDDSRLR – ∑*DSR* AEPFR) / (ATDSRL + ∑*DSR* ARI) – 1.0] \* 100**

**GREDP (MW) = ABS(∑*DSR*ATG – ∑*DSR* DBPOS – ATDSRL– ARRDDSRLR – AECRDDSRLR – ANSDDSRLR + Intra-QSE Purchase - Intra-QSE Sale – ∑*DSR* AEPFR – ∑*DSR*ARI)**

Where:

∑*DSR* ATG = Sum of Average Telemetered Generation for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval

∑*DSR*ARI = Sum of Average Regulation Instruction for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval

ATDSRL = Average Telemetered DSR Load = the average telemetered DSR Load for the QSE for the five-minute clock interval

Intra-QSE Purchase = Energy Trade where the QSE is both the buyer and seller with the flag set to “Purchase”

Intra-QSE Sale = Energy Trade where the QSE is both the buyer and seller with the flag set to “Sale”

∑*DSR*AEPFR = Sum of Average Estimated Primary Frequency Response for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval

∑*DSR*DBPOS = Sum of the difference between a linearly ramped Base Point minus Output Schedule for all Resources with a Resource Status of ONDSR or ONDSRREG of the QSE for the five-minute clock interval. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five minute period

ARRDDSRLR = Average Responsive Reserve Deployment DSR Load Resource = the average RRS energy deployment for the five-minute clock interval from Load Resources that are part of the DSR Load

AECRDDSRLR = Average ERCOT Contingency Response Deployment DSR Load Resource = the average ECRS energy deployment for the five-minute clock interval from Load Resources that are part of the DSR Load

ANSDDSRLR = Average Non-Spin Deployment DSR Load Resource = the average Non-Spin energy deployment for the five-minute clock interval from Load Resources that are part of the DSR Load

(4) For Controllable Load Resources that have a Resource Status of ONRGL or ONCLR, ERCOT shall compute the CLREDP. The CLREDP will be calculated both as a percentage and in MWs as follows:

**CLREDP (%) = ABS[((ATPC + AEPFR)/(ABP – ARI)) – 1.0] \* 100**

**CLREDP (MW) = ABS(ATPC – (ABP – AEPFR – ARI))**

Where:

ATPC = Average Telemetered Power Consumption = the average telemetered power consumption of the Controllable Load Resource for the five-minute clock interval

ARI = Average Regulation Instruction = the amount of regulation that the Controllable Load Resource should have produced based on the LFC deployment signals, calculated by LFC, during each five-minute clock interval. Reg-Up is considered a positive value for this calculation

AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05, the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval

ABP = Average Base Point = the time-weighted average of a linearly ramped Base Point for the five-minute clock interval. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five-minute period. The initial value of the linearly ramped Base Point will be the four second value of the previous linearly ramped Base Point at the time the new SCED Base Point is received into the ERCOT EMS. In the event that the SCED Base Point is received after the five minute ramp period, the linearly ramped Base Point will continue at a constant value equal to the ending four second value of the five-minute ramp.

(5) ERCOT shall post to the MIS Certified Area for each QSE and for all Generation Resources or Wind-powered Generation Resource (WGR) Groups that are not part of a DSR Portfolio, for the DSR Portfolios, and for all Controllable Load Resources:

(a) The percentage of the monthly five-minute clock intervals during which the Generation Resource or IRR Group was On-Line and released to SCED Base Point Dispatch Instructions;

(b) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR;

(c) The percentage of the monthly five-minute clock intervals during which the Generation Resource, IRR or Controllable Load Resource was providing Regulation Service;

(d) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was less than 2.5 MW;

(e) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was less than 2.5 MW;

(f) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(g) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(h) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR Group, or the DSR Portfolio was released to SCED that the GREDP was greater than 5.0 MW;

(i) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of either ONRGL or ONCLR that the CLREDP was greater than 5.0 MW;

(j) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was less than 2.5 MW;

(k) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was less than 2.5 MW;

(l) The percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(m) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;

(n) The percent of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource, the IRR, or the DSR Portfolio was providing Regulation Service that the GREDP was greater than 5.0 MW; and

(o) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was providing Regulation Service that the CLREDP was greater than 5.0 MW.

(6) ERCOT shall calculate the GREDP/CLREDP under normal operating conditions. ERCOT shall not consider five-minute clock intervals during which any of the following events has occurred:

(a) The five-minute intervals within the 20-minute period following an event in which ERCOT has experienced a Forced Outage causing an ERCOT frequency deviation of greater than 0.05 Hz;

(b) Five-minute clock intervals in which ERCOT has issued Emergency Base Points to the QSE;

(c) The five-minute clock interval following the Forced Outage of any Resource within the QSE’s DSR Portfolio that has a Resource Status of ONDSR or ONDSRREG;

(d) The five-minute clock intervals following a documented Forced Derate or Startup Loading Failure of a Generation Resource or any member IRR of an IRR Group. Upon request of the Reliability Monitor or ERCOT, the QSE shall provide the following documentation regarding each Forced Derate or Startup Loading Failure:

(i) Its generation log documenting the Forced Outage, Forced Derate or Startup Loading Failure;

(ii) QSE (COP) for the intervals prior to, and after the event; and

(iii) Equipment failure documentation which may include, but not be limited to, Generation Availability Data System (GADS) reports, plant operator logs, work orders, or other applicable information;

(e) The five-minute clock intervals where the telemetered Resource Status is set to ONTEST such as intervals during Ancillary Service Qualification and Testing as outlined in Section 8.1.1.1, Ancillary Service Qualification and Testing, or the five-minute clock intervals during general capacity testing requirements as outlined in Section 8.1.1.2, General Capacity Testing Requirements;

(f) The five-minute clock intervals where the telemetered Resource Status is set to STARTUP;

(g) The five-minute clock intervals where a Generation Resource’s ABP is below the average telemetered LSL;

(h) Certain other periods of abnormal operations as determined by ERCOT in its sole discretion;

(i) For a Controllable Load Resource, the five-minute clock intervals in which the computed Base Points are equal to the snapshot of its telemetered power consumption;

(j) For intervals where both the primary and backup Wide Area Network (WAN) connections are inoperative.

(7) All Generation Resources that are not part of a DSR Portfolio, excluding IRRs, and all DSR Portfolios shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) A Generation Resource or DSR Portfolio, excluding an IRR, must have a GREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which GREDP was calculated.

(b) If at the end of the month during which GREDP was calculated a DSR Portfolio has a GREDP less than X% or Y MW for 85% of the five-minute clock intervals, the Reliability Monitor shall, at the request of the QSE with the DSR Portfolio, recalculate GREDP excluding the five-minute clock intervals following the Forced Outage of any Resource within the QSE’s DSR Portfolio that has a Resource Status of ONDSR or ONDSRREG continuing until the start of the next Operating Hour for which the QSE is able to adjust. If the Forced Outage of the Resource occurs within ten minutes of the start of the next Operating Hour, then the Reliability Monitor shall not consider any of the five-minute intervals between the time of the Forced Outage and continuing until the start of the second Operating Hour for which the QSE is able to adjust. The requesting QSE shall provide to the Reliability Monitor information validating the Forced Outage including the time of the occurrence of the Forced Outage and documentation of the last submitted COP status prior to the Forced Outage of the Resource for the intervals in dispute.

(c) Additionally, all Generation Resources that are not part of a DSR Portfolio, excluding IRRs, and all DSR Portfolios will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) A Generation Resource or DSR Portfolio, excluding an IRR, must have a GREDP less than the greater of X% or Y MW. A Generation Resource or DSR Portfolio cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and GREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(8) All IRRs and IRR Groups shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output for 95% of the five-minute clock intervals in the month when the Resource or a member IRR of an IRR Group received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR’s HSL used by SCED or the IRR was instructed not to exceed its Base Point. The expected MW output includes the Resource’s Base Point, Regulation Service instructions, and any expected Primary Frequency Response.

(b) Additionally, all IRRs and IRR Groups will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources and IRR Groups must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(i) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output. An IRR or IRR Group cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and the Resource or a member of an IRR Group received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR’s HSL used by SCED or the IRR was instructed not to exceed its Base Point. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(9) All Controllable Load Resources shall meet the following CLREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:

(a) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which CLREDP was calculated.

(b) Additionally, all Controllable Load Resources will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following CLREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following Performance criteria to the Reliability Monitor:

(i) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW. A Controllable Load Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and CLREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.

(c) For Controllable Load Resources which are providing RRS, ECRS, or Non-Spin, the following intervals will be excluded from these calculations:

(i) Five-minute clock intervals which begin ten minutes or less after a deployment of RRS or ECRS was deployed to the Resource;

(ii) Five-minute clock intervals which begin ten minutes or less after a recall of RRS or ECRS when the Resource was deployed for RRS or ECRS;

(iii) Five-minute clock intervals which begin 30 minutes or less after a deployment of Non-Spin was deployed to the Resource; and

(iv) Five-minute clock intervals which begin 30 minutes or less after a recall of Non-Spin when the Resource was deployed for Non-Spin.

(10) The GREDP/CLREDP performance criteria in paragraphs (7) through (9) above shall be subject to review and approval by TAC. The GREDP/CLREDP performance criteria variables X, Y, and Z shall be posted to the ERCOT website no later than three Business Days after TAC approval.

(11) If at the end of the month during which GREDP was calculated, a non-DSR Resource or a QSE with DSR Resources, has a GREDP less than X% or Y MW for 85% of the five-minute clock intervals, the Reliability Monitor shall, at the request of the QSE, recalculate GREDP excluding the five-minute clock intervals when a Resource is deployed above the unit’s ramp rate due to ramp rate sharing between energy and Regulation Service, as described in Section 6.5.7.2, Resource Limit Calculator. The requesting QSE shall provide to the Reliability Monitor information validating the ramp rate violation for the intervals in dispute.

|  |
| --- |
| ***[NPRR879, NPRR963, NPRR965, NPRR1000, NPRR1046, NPRR1011, NPRR1014, and NPRR1029: Replace applicable portions of Section 8.1.1.4.1 above with the following upon system implementation for NPRR879, NPRR963, NPRR965, NPRR1000, NPRR1014, or NPRR1029; upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011; or upon system implementation of NPRR1000 for NPRR1000 and NPRR1046:]***  **8.1.1.4.1 Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics**  (1) ERCOT shall compute the GREDP for each Generation Resource that is On-Line and released to SCED for Base Point Dispatch Instructions. The GREDP is calculated for each five-minute clock interval as a percentage and in MWs as follows:  **GREDP (%) = ABS[((ATG – AEPFR)/(ASP)) – 1.0] \* 100**  **GREDP (MW) = ABS(ATG – AEPFR – ASP)**  Where:  ATG = Average Telemetered Generation = the average telemetered generation of the Generation Resource or for the aggregate of the IRRs within an IRR Group for the five-minute clock interval  ∆frequency is actual frequency minus 60 Hz  EPFR = Estimated Primary Frequency Response (MW) = if │∆frequency│≤ Governor Dead-Band then EPFR = zero, if not then if ∆frequency > zero, EPFR = (∆frequency - Governor Dead-Band)/((droop value \* 60) – Governor Dead-Band) \* HSL \* -1, if not then if ∆frequency < zero, EPFR = (∆frequency + Governor Dead-Band)/((droop value \* 60) – Governor Dead-Band) \* HSL \* -1  AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05 the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval. For Combined Cycle Generation Resources with Non-Frequency Responsive Capacity (NFRC), the HSL to calculate the EPFR will be based on the Resource’s high limit of the capacity that is frequency responsive. For Combined Cycle Generation Resources, 5.78% Governor droop shall be used. The Resource-specific calculations will be aggregated for IRR Groups.  ASP = Average Set Point = the time-weighted average of the Resource’s Updated Desired Set Point (UDSP) for the five-minute clock interval  (2) For Controllable Load Resources that have a Resource Status of ONL and are acting as a Controllable Load Resource, ERCOT shall compute the CLREDP. The CLREDP will be calculated both as a percentage and in MWs as follows:  **CLREDP (%) = ABS[((ATPC + AEPFR)/(ASP)) – 1.0] \* 100**  **CLREDP (MW) = ABS(ATPC – (ASP – AEPFR))**  Where:  ATPC = Average Telemetered Power Consumption = the average telemetered power consumption of the Controllable Load Resource for the five-minute clock interval  AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource specific droop value where 5% droop = 0.05, the Governor Dead-Band (Hz) and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval  ASP = Average Set Point = the time-weighted average of the Resource’s UDSP for the five-minute clock interval  (3) ERCOT shall compute the ESREDP for ESRs. The ESREDP is calculated for each five-minute clock interval as a percentage and in MWs as follows:  **ESREDP (%) = ABS[((ATPF – AEPFR)/(ASP)) – 1.0] \* 100**  **ESREDP (MW) = ABS(ATPF – AEPFR – ASP)**  Where:  ATPF = Average Telemetered Power Flow = the average telemetered power flow of the Energy Storage Resource for the five-minute clock interval.  ASP = Average Set Point = the time-weighted average of UDSP, for the five-minute clock interval.  ∆frequency is actual frequency minus 60 Hz.  EPFR = Estimated Primary Frequency Response (MW) = If │∆frequency│≤ Governor Dead-Band then EPFR = zero, if not then if ∆frequency > zero, EPFR = (∆frequency - Governor Dead-Band)/((droop value \* 60) – Governor Dead-Band) \* ABS(HSL-LSL) \* -1, if not then if ∆frequency < zero, EPFR = (∆frequency + Governor Dead-Band)/((droop value \* 60) – Governor Dead-Band) \* ABS(HSL-LSL) \* -1.  AEPFR = Average Estimated Primary Frequency Response = the Estimated Primary Frequency Response (MW) will be calculated every four seconds using a Resource-specific droop value where 5% droop = 0.05, the Governor Dead-Band (Hz), Resource LSL (MW), and Resource HSL (MW) provided by the Resource Entity, and the frequency deviation (Hz) from 60 Hz and averaged for the five-minute clock interval.  (4) ERCOT shall post to the MIS Certified Area for each QSE and for all Generation Resources, ESRs, Wind-powered Generation Resource (WGR) Groups, and Controllable Load Resources, as applicable:  (a) The percentage of the monthly five-minute clock intervals during which the Generation Resource or IRR Group was On-Line and released to SCED Base Point Dispatch Instructions;  (b) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL;  (c) The percentage of the monthly five-minute clock intervals during which the ESR had a Resource Status of ON;  (d) The percentage of the monthly five-minute clock intervals during which the Generation Resource, IRR, ESR, or Controllable Load Resource was awarded Regulation Service;  (e) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was less than 2.5 MW;  (f) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was less than 2.5 MW;  (g) The percentage of the monthly five-minute clock intervals during which the ESR was released to SCED that the ESRESDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the ESR was released to SCED that the ESRESDP was less than 2.5 MW;  (h) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;  (i) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;  (j) The percentage of the monthly five-minute clock intervals during which the ESR was released to SCED that the ESREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the ESR was released to SCED that the ESREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;  (k) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR Group was released to SCED that the GREDP was greater than 5.0 MW;  (l) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource had a Resource Status of ONL that the CLREDP was greater than 5.0 MW;  (m) The percentage of the monthly five-minute clock intervals during which the ESR was released to SCED that the ESREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the ESR was released to SCED that the ESREDP was greater than 5.0 MW;  (n) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was less than 2.5 MW;  (o) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was less than 2.5 MW;  (p) The percentage of the monthly five-minute clock intervals during which the ESR was awarded Regulation Service that the ESREDP was less than 2.5% and the percentage of the monthly five-minute clock intervals during which the ESR was awarded Regulation Service that the ESREDP was less than 2.5 MW;  (q) The percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;  (r) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;  (s) The percentage of the monthly five-minute clock intervals during which the ESR was awarded Regulation Service that the ESREDP was equal to or greater than 2.5% and equal to or less than 5.0% and the percentage of the monthly five-minute clock intervals during which the ESR was awarded Regulation Service that the ESREDP was equal to or greater than 2.5 MW and equal to or less than 5.0 MW;  (t) The percent of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Generation Resource or the IRR was awarded Regulation Service that the GREDP was greater than 5.0 MW;  (u) The percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the Controllable Load Resource was awarded Regulation Service that the CLREDP was greater than 5.0 MW; and  (v) The percent of the monthly five-minute clock intervals during which the ESR was awarded Regulation Service that the ESREDP was greater than 5.0% and the percentage of the monthly five-minute clock intervals during which the ESR was awarded Regulation Service that the ESREDP was greater than 5.0 MW.  (5) ERCOT shall calculate the GREDP/CLREDP/ESREDP under normal operating conditions. ERCOT shall not consider five-minute clock intervals during which any of the following events has occurred:  (a) The five-minute intervals within the 20-minute period following an event in which ERCOT has experienced a Forced Outage causing an ERCOT frequency deviation of greater than 0.05 Hz;  (b) Five-minute clock intervals in which ERCOT has issued Emergency Base Points to the QSE;  (c) The five-minute clock intervals following a documented Forced Derate or Startup Loading Failure of a Generation Resource, ESR, or any member IRR of an IRR Group. Upon request of the Reliability Monitor or ERCOT, the QSE shall provide the following documentation regarding each Forced Derate or Startup Loading Failure:  (i) Its generation log documenting the Forced Outage, Forced Derate or Startup Loading Failure;  (ii) QSE (COP) for the intervals prior to, and after the event; and  (iii) Equipment failure documentation which may include, but not be limited to, Generation Availability Data System (GADS) reports, plant operator logs, work orders, or other applicable information;  (d) The five-minute clock intervals where the telemetered Resource Status is set to ONTEST such as intervals during Ancillary Service Qualification and Testing as outlined in Section 8.1.1.1, Ancillary Service Qualification and Testing, or the five-minute clock intervals during general capacity testing requirements as outlined in Section 8.1.1.2, General Capacity Testing Requirements;  (e) The five-minute clock intervals where the telemetered Resource Status is set to STARTUP;  (f) The five-minute clock intervals where a Generation Resource’s ASP is below the average telemetered LSL;  (g) Certain other periods of abnormal operations as determined by ERCOT in its sole discretion;  (h) For a Controllable Load Resource, the five-minute clock intervals in which the computed Base Points are equal to the snapshot of its telemetered power consumption;  (i) For intervals where both the primary and backup Wide Area Network (WAN) connections are inoperative; and  (j) For QSGRs, the five-minute clock intervals in which the QSGR has a telemetered status of SHUTDOWN or telemeters an LSL of zero pursuant to Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process.  (6) All Generation Resources, excluding IRRs, shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (a) A Generation Resource, excluding an IRR, must have a GREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which GREDP was calculated.  (b) Additionally, all Generation Resources, excluding IRRs, will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (i) A Generation Resource, excluding an IRR, must have a GREDP less than the greater of X% or Y MW. A Generation Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and GREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.  (7) All IRRs and IRR Groups shall meet the following GREDP criteria for each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (a) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output for 95% of the five-minute clock intervals in the month when the Resource or a member IRR of an IRR Group was not awarded Ancillary Service and received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR’s HSL used by SCED or the IRR was instructed not to exceed its Base Point. The expected MW output includes the Resource’s Base Point, Regulation Service instructions, and any expected Primary Frequency Response.  (b) An IRR or IRR Group must have a GREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which the Resource or a member IRR of an IRR Group was awarded Ancillary Service.  (c) Additionally, all IRRs and IRR Groups will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources and IRR Groups must meet the following GREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (i) An IRR or IRR Group must have a GREDP less than Z% or the ATG must be less than the expected MW output. An IRR or IRR Group cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and the Resource or a member of an IRR Group was not awarded Ancillary Service and received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the IRR’s HSL used by SCED or the IRR was instructed not to exceed its Base Point. The performance will be measured separately for each instance in which ERCOT has declared EEA.  (ii) An IRR or IRR Group must have a GREDP less than the greater of X% or Y MW when the Resource or a member IRR of an IRR Group was awarded Ancillary Service. An IRR or IRR Group cannot fail this criteria more than three five-minute clock intervals during which EEA was declared. The performance will be measured separately for each instance in which ERCOT has declared EEA.  (8) All Controllable Load Resources shall meet the following CLREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (a) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW for 85% of the five-minute clock intervals in the month during which CLREDP was calculated.  (b) Additionally, all Controllable Load Resources will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following CLREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following Performance criteria to the Reliability Monitor:  (i) A Controllable Load Resource must have a CLREDP less than the greater of X% or Y MW. A Controllable Load Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and CLREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.  (c) For Controllable Load Resources which are providing RRS, ECRS, or Non-Spin, the following intervals will be excluded from these calculations:  (i) Five-minute clock intervals which begin ten minutes or less after a deployment of RRS or ECRS was deployed to the Resource;  (ii) Five-minute clock intervals which begin ten minutes or less after a recall of RRS or ECRS when the Resource was deployed for RRS or ECRS;  (iii) Five-minute clock intervals which begin 30 minutes or less after a deployment of Non-Spin was deployed to the Resource; and  (iv) Five-minute clock intervals which begin 30 minutes or less after a recall of Non-Spin when the Resource was deployed for Non-Spin.  (9) All ESRs shall meet the following ESREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (a) An ESR must have an ESREDP less than the greater of V% or W MW for 85% of the five-minute clock intervals in the month during which ESREDP was calculated.  (b) Additionally, all ESRs will also be measured for performance specifically during intervals in which ERCOT has declared EEA Level 1 or greater. These Resources must meet the following ESREDP criteria for the time window that includes all five-minute clock intervals during which EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (i) An ESR must have an ESREDP less than the greater of V% or W MW. An ESR cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and ESREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.  (10) DC-Coupled Resources shall meet the following ESREDP criteria each month. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (a) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (1) of Section 3.8.7, DC-Coupled Resources, the DC-Coupled Resource must have an ESREDP less than the greater of V% or W MW for 85% of the five-minute clock intervals in the month during which ESREDP for the DC-Coupled Resource was calculated.  (b) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (2) of Section 3.8.7, the DC-Coupled Resource must have an ESREDP less than Z% or the ATG must be less than the expected MW output for 95% of the five-minute clock intervals in the month when the DC-Coupled Resource received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the DC-Coupled Resource’s HSL used by SCED or the IRR was instructed not to exceed its Base Point. The expected MW output includes the Resource’s Base Point and any expected Primary Frequency Response.  (c) Additionally, all DC-Coupled Resources will be measured for performance during intervals in which ERCOT has declared an EEA. These Resources must meet the following ESREDP criteria for the time window that includes all five-minute clock intervals during which the EEA was declared. ERCOT will report non-compliance of the following performance criteria to the Reliability Monitor:  (i) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (1) of Section 3.8.7, the DC-Coupled Resource must have an ESREDP less than the greater of V% or W MW. A DC-Coupled Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and ESREDP was calculated. The performance will be measured separately for each instance in which ERCOT has declared EEA.  (ii) For each five-minute clock interval in which a DC-Coupled Resource meets the conditions in paragraph (2) of Section 3.8.7, the DC-Coupled Resource must have a ESREDP less than Z% or the ATG must be less than the expected MW output. A DC-Coupled Resource cannot fail this criteria more than three five-minute clock intervals during which EEA was declared and the DC-Coupled Resource received a Base Point Dispatch Instruction in which the Base Point was two MW or more below the DC-Coupled Resource’s HSL used by SCED or the IRR was instructed not to exceed its Base Point. The performance will be measured separately for each instance in which ERCOT has declared EEA.  (11) The GREDP/CLREDP/ESREDP performance criteria in paragraphs (6) through (10) above shall be subject to review and approval by TAC. The GREDP/CLREDP/ESREDP performance criteria variables V, W, X, Y, and Z shall be posted to the ERCOT website no later than three Business Days after TAC approval.  (12) If at the end of the month during which GREDP was calculated, a Resource has a GREDP less than X% or Y MW for 85% of the five-minute clock intervals, the Reliability Monitor shall, at the request of the QSE, recalculate GREDP excluding the five-minute clock intervals when a Resource is deployed above the unit’s ramp rate due to ramp rate sharing between energy and Regulation Service. The requesting QSE shall provide to the Reliability Monitor information validating the ramp rate violation for the intervals in dispute. |

**8.2 ERCOT Performance Monitoring**

(1) ERCOT shall continually assess its operations performance for the following activities:

(a) Coordinating the wholesale electric market transactions;

(b) System-wide transmission planning; and

(c) Network reliability.

(2) The Technical Advisory Committee (TAC), or a subcommittee designated by TAC, shall review ERCOT’s performance in controlling the ERCOT Control Area according to requirements and criteria set out in the TAC- and ERCOT Board-approved monitoring program. Assessments and reports include the following ERCOT activities:

(a) Transmission control:

(i) Transmission system availability statistics;

(ii) Outage scheduling statistics for Transmission Facilities Outages (maintenance planning, construction coordination, etc.); and

(iii) Metrics describing performance of the State Estimator;

(b) Resource control:

(i) Outage scheduling statistics for Resource facilities Outages (maintenance planning, construction coordination, etc.);

(ii) Resource control metrics as defined in the Operating Guides;

(iii) Metrics describing Reliability Unit Commitment (RUC) commitments and deployments;

(iv) Metrics describing conflicting instructions to Generation Resources and Energy Storage Resources (ESRs) from interval to interval;

(v) Metrics describing the overall Resource response to frequency deviations in the ERCOT Region; and

(vi) Voltage and reactive control performance;

(c) Settlement stability:

(i) Track number of price changes that occur after a Settlement Statement has posted for an Operating Day;

(ii) Track number and types of disputes submitted to ERCOT and their disposition;

(iii) Report on compliance with timeliness of response to disputes;

(iv) Number of resettlements required due to non-price errors pursuant to paragraphs (2) and (4) of Section 9.2.5, DAM Resettlement Statement, and paragraph (2) of Section 9.5.6, RTM Resettlement Statement;

(v) Other Settlement metrics; and

(vi) Availability of Electric Service Identifier (ESI ID) consumption data in conformance with Settlement timeline;

(d) Performance in implementing network model updates;

(e) Network Operations Model validation, by comparison to other appropriate models or other methods;

(f) System and Organization Control (SOC) audit results regarding ERCOT’s market Settlements operations;

(g) Net Allocation to Load:

(i) ERCOT shall calculate and report on a quarterly basis all charges allocated to Load for all Qualified Scheduling Entities (QSEs) for each month for the most recent thirteen months expressed in total dollars. ERCOT will sum all charges allocated to Load for all QSEs, and divide that total by the total Real-Time Adjusted Metered Load (AML), showing results in dollars per MWh.

(ii) The Load-Allocated CRR Monthly Revenue Zonal Amount (LACMRZAMT), as calculated in paragraph (5) of Section 7.5.7, Method for Distributing CRR Auction Revenues, will be summed by Congestion Management Zone (CMZ) for each month for the most recent 13 months, and divided by the sum of the Real-Time AML by CMZ for each month, showing results in dollars per MWh per CMZ.

(iii) ERCOT will calculate the total dollars per MWh by CMZ by summing all charges allocated to Load for all QSEs, excluding LACMRZAMT, and dividing that total by the Real-Time AML; this rate will then be added to item (ii) above to calculate the total dollars per MWh by CMZ.

**8.4 ERCOT Response to Market Non-Performance**

(1) ERCOT may require a Market Participant to develop and implement a corrective action plan to address its failure to meet performance criteria in this Section. The Market Participant must deliver a copy of this plan to ERCOT and must report to ERCOT periodically on the status of the implementation of the corrective action plan.

(2) ERCOT may revoke any or all Ancillary Service qualifications of any Generation Resource, Energy Storage Resource (ESRs), or Load Resource for continued material non-performance in providing Ancillary Service capacity or energy.

(3) ERCOT may suspend any Emergency Response Service (ERS) Resource for continued material non-performance in providing ERS.

***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 + Energy Storage Resources (ESRs) + Settlement Only Generators (SOGs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual Direct Current Tie (DC Tie) imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity’s (NOIE’s) Load - actual DC Tie exports - Wholesale Storage Load (WSL).

|  |
| --- |
| ***[NPRR995: Replace paragraph (3) above with the following upon system implementation:]***  (3) Coincidental MW peak is defined as the highest monthly Settlement Interval 15-minute MW peak for the entire ERCOT Transmission Grid as calculated per the following formula: The sum of all net energy produced by Generation Resources + Settlement Only Generators (SOGs) + Settlement Only Energy Storage Systems (SOESSs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual Direct Current Tie (DC Tie) imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity’s (NOIE’s) Load - actual DC Tie exports - Wholesale Storage Load (WSL). |

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

**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 (the “reference month”), and is calculated as follows:

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

Where:

MMARS *cp* = MMA *cp* / MMATOT

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

|  |
| --- |
| ***[NPRR995, NPRR1012, and NPRR1201: Replace applicable portions of the formula “MMA cp” above with the following upon system implementation for NPRR995 or NPRR1201; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]***  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*),  ∑*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)

|  |
| --- |
| ***[NPRR1201: Delete the formulas “UOPTS mp”, “UOBLS mp”, “UOPTP mp”, and “UOBLP mp” above upon system implementation.]*** |

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* ) |

USOGTOT *mp* = ∑*gsc* (MEBSOGNET *mp, gsc*) + ∑ *p, i* (RTMGSOGZ *mp, p, i*)

|  |
| --- |
| ***[NPRR995: Insert the formula “USOCLTOT mp” below upon system implementation:]***  USOCLTOT *mp* = (-1) \* ∑*gsc, b* (WSOL *mp, gsc, b*) |

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| DURSCP *cp* | $ | *Default Uplift Ratio Share per Counter-Party*—The Counter-Party’s pro rata portion of the total short-pay amount for all Day-Ahead Market (DAM) and Real-Time Market (RTM) Invoices for a month. |
| TSPA | $ | *Total Short Pay Amount*—The total short-pay amount calculated by ERCOT to be collected through the Default Uplift Invoice process. |
| MMARS *cp* | None | *Maximum MWh Activity Ratio Share*—The Counter-Party’s pro rata share of Maximum MWh Activity in the reference month. |
| MMA *cp* | MWh | *Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction in the reference month. |
| MMATOT | MWh | *Maximum MWh Activity Total*—The sum of all Counter-Party’s Maximum MWh Activity in the reference month. |
| RTMG *mp, p, r, i* | MWh | *Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the 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 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.   |  | | --- | | ***[NPRR1188: Replace the definition above with the following upon system implementation:]***  *Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*’s DAM Energy Bids and Energy Bid Curves, cleared in the DAM, at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE. | |
| 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.   |  | | --- | | ***[NPRR1188: Replace the definition above with the following upon system implementation:]***  *Uplift Day-Ahead Energy Purchase per Market Participant*—The monthly total of energy represented by Market Participant *mp*’s DAM Energy Bids and Energy Bid Curves, cleared in the DAM, where the Market Participant is a QSE assigned to the registered Counter-Party. | |
| RTOBL *mp, (j, k), h* | MW | *Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*’s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE. |
| URTOBL *mp* | MWh | *Uplift Real-Time Obligation per Market Participant*—The monthly total of Market Participant *mp*’s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTOBLLO *q, (j, k)* | MW | *Real-Time Obligation with Links to an Option per QSE per pair of source and sink*⎯The total MW of the QSE’s PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour. |
| URTOBLLO *q, (j, k)* | MW | *Uplift Real-Time Obligation with Links to an Option per QSE per pair of source and sink*⎯The monthly total of Market Participant *mp*’s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| DAOPT *mp, (j, k), h* | MW | *Day-Ahead Option per Market Participant per source and sink pair per hour*⎯The number of Market Participant *mp*’s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder. |
| UDAOPT *mp* | MWh | *Uplift Day-Ahead Option per Market Participant*⎯The monthly total of Market Participant *mp*’s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| DAOBL *mp, (j, k), h* | MW | *Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*’s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder. |
| UDAOBL *mp* | MWh | *Uplift Day-Ahead Obligation per Market Participant*⎯The monthly total of Market Participant *mp*’s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OPTS *mp, (j, k), a, h* | MW | *PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOPTS *mp* | MWh | *Uplift PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OBLS *mp, (j, k), a, h* | MW | *PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOBLS *mp* | MWh | *Uplift PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OPTP *mp, (j, k), a, h* | MW | *PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOPTP *mp* | MWh | *Uplift PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OBLP *mp, (j, k), a, h* | MW | *PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| UOBLP *mp* | MWh | *Uplift PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*’s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| |  | | --- | | ***[NPRR1201: Delete the variables “OPTS mp, (j, k), a, h”, “UOPTS mp”, “OBLS mp, (j, k), a, h”, “UOBLS mp”, “OPTP mp, (j, k), a, h”, “UOPTP mp”, “OBLP mp, (j, k), a, h”, “UOBLP mp” above upon system implementation.]*** | | | |
| UWSLTOT *mp* | MWh | *Uplift Metered Energy for Wholesale Storage Load at bus per Market Participant*⎯The monthly sum of Market Participant *mp*’s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL. |
| MEBL *mp, r, b* | MWh | *Metered Energy for Wholesale Storage Load at bus*⎯The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*. |
| |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | | ***[NPRR1012: Insert the variables below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***   |  |  |  | | --- | --- | --- | | UDAASOAWD *mp* | MWh | *Uplift Day-Ahead Ancillary Service Only Award per Market Participant—*The monthly total of Market Participant *mp’s* Ancillary Service Only Offers awarded in DAM, where the Market Participant is a QSE assigned to the registered Counter-Party. | | DARUOAWD *mp, h* | MW | *Day-Ahead Reg-Up Only Award per Market Participant*⎯The Reg-Up Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DARDOAWD *mp, h* | MW | *Day-Ahead Reg-Down Only Award per Market Participant*⎯The Reg-Down Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DARROAWD *mp, h* | MW | *Day-Ahead Responsive Reserve Only Award per Market Participant*⎯ The Responsive Reserve (RRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DANSOAWD *mp, h* | MW | *Day-Ahead Non-Spin Only Award per Market Participant*⎯The Non-Spin Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | DAECROAWD *mp, h* | MW | *Day-Ahead ERCOT Contingency Reserve Service Only Award per Market Participant*⎯The ERCOT Contingency Reserve Service (ECRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*. | | | | |
| USOGTOT *mp* | MWh | *Uplift Real-Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by Settlement Only Generators (SOGs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.   |  | | --- | | ***[NPRR995: Replace the definition above with the following upon system implementation:]***  *Uplift Real-Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by Settlement Only Generators (SOGs), Settlement Only Distribution Generators (SODGs), Settlement Only Transmission Generators (SOTGs), Settlement Only Distribution Energy Storage Systems (SODESSs), or Settlement Only Transmission Energy Storage Systems (SOTESSs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. | |
| |  |  |  |  | | --- | --- | --- | --- | | ***[NPRRR995: Insert the variable “USOCLTOT mp” below upon system implementation:]***   |  |  |  | | --- | --- | --- | | USOCLTOT *mp* | MWh | *Uplift Real-Time Settlement Only Charging Load per Market Participant*—The monthly sum of Real-Time charging Load that is WSL by SODESSs and SOTESSs represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. | | | | |
| RTMGSOGZ *mp. p, i* | MWh | *Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Energy Storage System (ESS), Settlement Only Distribution Generators (SODGs), and Settlement Only Transmission Generators (SOTGs) at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that opted out of nodal pricing pursuant to Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG), will also be included in this value.   |  | | --- | | ***[NPRR995: Replace the definition above with the following upon system implementation:]***  *Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Energy Storage System (ESS), SODGs, and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that opted out of nodal pricing pursuant to Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS), will also be included in this value. | |
| MEBSOGNET *q, gsc* | MWh | *Net Metered energy at gsc for an SODG or SOTG Site*⎯The net sum for all Settlement Meters for SODG or SOTG site *gsc* represented by QSE *q*. A positive value indicates an injection of power to the ERCOT System.   |  | | --- | | ***[NPRR995: Replace the definition above with the following upon system implementation:]***  *Net Metered energy at gsc for an SODG, SOTG, SODESS, or SOTESS Site*⎯The net sum for all Settlement Meters for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by QSE *q* for the 15-minute Settlement Interval. A positive value indicates an injection of power to the ERCOT System. | |
| |  |  |  |  | | --- | --- | --- | --- | | ***[NPRRR995: Insert the variable “WSOL mp, gsc, b” below upon system implementation:]***   |  |  |  | | --- | --- | --- | | WSOL *mp, gsc, b* | MWh | *WSL for an SODESS or SOTESS Site*⎯The WSL as measured for an for SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by the Market Participant *mp,* represented as a negative value, for the 15-minute Settlement Interval. | | | | |
|  | | |
| *cp* | none | A registered Counter-Party. |
| *mp* | none | A Market Participant with MWh activity in the reference month that is a currently-registered QSE or CRR Account Holder or that voluntarily terminated its QSE or CRR Account Holder registration. |
| *j* | none | A source Settlement Point. |
| *k* | none | A sink Settlement Point. |
| *a* | none | A CRR Auction. |
| *p* | none | A Settlement Point. |
| *i* | none | A 15-minute Settlement Interval. |
| *h* | none | The hour that includes the Settlement Interval i. |
| *r* | none | A Resource. |
| *gsc* | none | A generation site code. |
| *b* | none | An Electrical Bus. |

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

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

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

(6) Each Default Uplift Invoice must contain:

(a) The Invoice Recipient’s name;

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

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

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

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

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

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

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

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

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

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

(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.

|  |
| --- |
| ***[NPRR1188: Insert paragraph (e) below upon system implementation:]***  (e) Load that has TDSP read meter(s) and is participating as a Controllable Load Resource (CLR) that is not an Aggregate Load Resource (ALR). The CLR must be metered separately from all other Loads and generation. |

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

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

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

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

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

***10.3.2.1.6 Allocating EPS Metered Data to Generator Owners When It Is Net Load***

(1) EPS Generation Resource and Energy Storage Resource (ESR) sites that are netted by ERCOT may have multiple Competitive Retailers (CRs) associated with the Load. ERCOT shall poll the EPS metering facilities related to the actual Generation Resource or ESR facility and store the meter data at 15-minute intervals. ERCOT shall perform validation, editing, estimation, compensation for losses as necessary, and netting as required for EPS metering data. For intervals when data is net Load, the fixed ownership percentages stored in the asset database must be used to allocate the consumption to multiple Electric Service Identifiers (ESI IDs). The consumption quantities for the ESI IDs must be used in all energy settlement calculations and reports.

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

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

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

(a) Single POI or Service Delivery Point;

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

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

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

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

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

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

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

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

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

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (3) above with the following upon system implementation:]***  (3) For Energy Storage Resource (ESR), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.  (a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:  (i) The total energy into the ESR, SODESS, or SOTESS must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities; and  (ii) The auxiliary Load energy shall be stored in the EPS Meter’s IDR, per channel assignments defined in the SMOG.  (b) For configurations where the WSL is not at a POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and  (c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (7) below. |

|  |
| --- |
| ***[NPRR1188: Insert paragraph (4) below upon system implementation and renumber accordingly:]***  (4) For a generation site with a single POI and one or more Controllable Load Resources (CLRs) behind the POI, an EPS Meter to separately measure each CLR Load is required. The TDSP(s) must install the EPS Meter only if all of the Entities consuming energy behind the POI, including the Resource Entity for such generation site, consent in writing to the metering arrangement, and the arrangement is included in an EPS Design Proposal that is approved by ERCOT. The CLR shall provide notice to all Entities consuming energy behind the POI of its request for installation of an EPS Meter. |

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

(7) For purposes of this Section, a common switchyard is defined as an electric substation Facility where the POI for Load and Generation Resources or ESRs 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 or ESR to its POI cannot be Facilities that have been placed in a TSP’s or DSP’s rate base.

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

|  |
| --- |
| ***[NPRR945: Insert paragraph (9) below upon system implementation and renumber accordingly:]***  (9) ERCOT shall post on the ERCOT website a report listing all Generation Resources, ESRs, or Settlement Only Generators (SOGs) that have achieved commercial operations, excluding Decommissioned Generation Resources or decommissioned ESRs, Mothballed Generation Resources or Mothballed ESRs, and decommissioned SOGs, whose Resource Registration data indicates that the Generation Resource, ESR, or SOG is part of a Private Use Network. The report must identify the name of the Generation Resource, ESR, or SOG site, its nameplate capacity, and the date the Generation Resource, ESR, 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. |

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

**10.3.2.4 Reporting of Net Generation Capacity**

(1) Each Resource Entity with either a Generation Resource, ESR, or Settlement Only Transmission Self-Generator (SOTSG) in a Private Use Network shall complete and submit the declaration in Section 22, Attachment L, Declaration of Private Use Network Net Generation Capacity Availability, to ERCOT by February 1 of each year, stating its projected annual changes in net generation capacity available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and annual changes as of May 31 for the next ten subsequent years. ERCOT will use the aggregated capacity forecasts for the Report on Capacity, Demand and Reserves in the ERCOT Region, pursuant to Section 3.2.6.2.2, Total Capacity Estimate.

***11.5.2 Generation Meter Data Aggregation***

(1) ERCOT will perform generation aggregation by the following distinct criteria sets:

(a) By UFE zone: This data set is used in the calculation of UFE in the Load aggregation process; and

(b) By Generation Resource or Energy Storage Resource (ESR) (Resource ID (RID)), by Resource Entities, by QSE and Settlement Point: This data set is passed to the Settlement process for generation imbalance calculations.

**11.5.2.1 Participant Specific Generation Data Posting/Availability**

(1) The following market-specific generation information will be made available by ERCOT to each Market Participant:

(a) Generation unit production by Generation Resource or ESR Entity; and

(b) Generation unit production by QSE.

(2) Each Market Participant will have access only to its own information and/or the information of the Entities, which it represents. ERCOT will make the aforementioned data for each Settlement run available to Market Participants via the MIS Certified Area within 48 hours of finalizing the data for Settlement statements.

***13.2.4 Seasonal Transmission Loss Factor Calculation***

(1) Seasonal on-peak and off-peak TLFs are derived from the annually updated ERCOT on-peak and off-peak load flow base cases analysis by ERCOT. Base cases reflect the most current data on the transmission system and Generation Resource and Energy Storage Resource (ESR) Dispatch. The ERCOT Transmission Grid topology and related Generation Resource and ESR Dispatch in the base cases are the critical factors in calculating losses. Seasonal time periods are defined as follows:

(a) Spring (March – May)

(b) Summer (June – September)

(c) Fall (October – November)

(d) Winter (December – February)

(2) ERCOT shall calculate seasonal TLFs by dividing ERCOT seasonal case Transmission Losses (60 kV system and higher) by the ERCOT seasonal base Load adjusted (reduced) for self-serve Load modeled in the case. The resulting TLFs are expressed as a percentage of Load.

(3) ERCOT shall post the seasonal TLFs to the ERCOT website prior to the start of the year for the next four seasons beginning with the Spring season.

|  |
| --- |
| ***[NPRR1145: Replace Section 13.2.4 above with the following upon system implementation:]***  ***13.2.4 Seasonal On-Peak and Off-Peak Transmission Loss Factor Calculation***  (1) Seasonal On-Peak and Off-Peak TLFs are derived from the annually updated ERCOT on-peak and off-peak load flow base cases analysis by ERCOT. Base cases reflect the most current data on the transmission system and Generation Resource Dispatch. The ERCOT Transmission Grid topology and related Generation Resource Dispatch in the base cases are the critical factors in calculating losses. Seasonal time periods are defined as follows:  (a) Spring (March – May)  (b) Summer (June – September)  (c) Fall (October – November)  (d) Winter (December – February)  (2) ERCOT shall calculate seasonal TLFs by dividing ERCOT seasonal case Transmission Losses (60 kV system and higher) by the ERCOT seasonal base Load adjusted (reduced) for self-serve Load modeled in the case. The resulting TLFs are expressed as a percentage of Load.  (3) ERCOT shall post the seasonal TLFs to the ERCOT website prior to the start of the year for the next four seasons beginning with the Spring season. |

**16.5 Registration of a Resource Entity**

(1) A Resource Entity owns or controls a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT’s reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource or SOG through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. A Resource Entity may submit a proposal to register a SOG consisting of an Energy Storage System (ESS) or a combination of ESS and non-ESS generation. The Resource Entity must identify all components of the SOG as part of the Resource Registration process.

|  |
| --- |
| ***[NPRR995: 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 (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. If a Resource Entity intends to register one or more Energy Storage Systems (ESSs) and one or more non-ESS generators as SOGs at the same site, the Resource Entity must provide an affidavit attesting to the amount of ESS and non-ESS capacity at the site as a condition for registration. |

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

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

|  |
| --- |
| ***[NPRR995: 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, ESR, Settlement Only Transmission Generator (SOTG), or Settlement Only Transmission Self-Generator (SOTSG) in the event of any of the following conditions:

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

(b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, or SOTSG; or

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

|  |
| --- |
| ***[NPRR995: Replace paragraph (4) above with the following upon system implementation:]***  (4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:  (a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT’s satisfaction that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS can comply with these standards;  (b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, SOTSG, or SOTESS; or  (c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT. |

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

**16.14 Termination of Access Privileges to Restricted Computer Systems and Control Systems**

(1) All Market Participants and ERCOT are required to have processes in place to terminate access privileges, as soon as practicable, to Restricted Systems for any employee, consultant, or contractor, upon termination of employment or where access is no longer required.

(2) “Restricted Systems” include computer or control systems that are essential to the operation of Restricted Facilities.

(3) “Restricted Facilities” include Facilities and assets that support the reliable operation of the bulk ERCOT System (100 kV and above), such as but not limited to:

(a) Generation Resources and Energy Storage Resources (ESRs);

(b) Transmission substations;

(c) Control/dispatch centers and backup control/dispatch centers related to items (a) and (b) above;

(d) Systems and Facilities critical to system restoration (including but not limited to Black Start generators and substations); and

(e) Systems and Facilities critical to automatic firm load shedding.

(4) Access privilege is defined to include computer and electronic access.

(5) Each Market Participant and ERCOT shall have internal controls in place to ensure these processes are reviewed at least on an annual basis.

(6) Each Market Participant and ERCOT are required to notify the compliance monitoring authority within two Business Days after the discovery of any incident where a terminated employee, contractor or employee of a contractor has accessed a Restricted System when access privileges have been or should have been revoked.

(7) Failure by a Market Participant or ERCOT to follow its processes that results in access to any Restricted Systems by any employee, consultant, contractor or affiliate after his or her termination will be considered a violation of these Protocols.

**26.2 Securitization Default Charges**

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

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

**SDCRSCP** ***cp* = TSDCMA \* SDCMMARS** ***cp***

Where:

SDCMMARS *cp* = SDCMMA *cp* / SDCMMATOT

SDCMMA *cp* = Max { ∑*mp* (SDCRTMG *mp*+ SDCRTDCIMP *mp*),

∑*mp* (SDCRTAML *mp* + SDCWSLTOT *mp*),

∑*mp*SDCRTQQES *mp*,

∑*mp* SDCRTQQEP *mp*,

∑*mp* SDCDAES *mp*,

∑*mp* SDCDAEP *mp*,

∑*mp* (SDCRTOBL *mp +* SDCRTOBLLO *mp*),

∑*mp* (SDCDAOPT *mp*+ SDCDAOBL *mp*+SDCOPTS *mp*+SDCOBLS *mp*),

∑*mp* (SDCOPTP *mp*+ SDCOBLP *mp*)}

SDCMMATOT = ∑*cp* (SDCMMA *cp*)

Where:

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

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

**S**DCRTAML *mp* = max(0,∑*p, i* (RTAMLEXSECM *mp, p, i*))

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

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

**S**DCDAES *mp* = ∑*p, h* (DAES *mp, p, h*)

**S**DCDAEP *mp* = ∑*p, h* (DAEP *mp, p, h*)

**S**DCRTOBL *mp* = ∑*(j, k), h* (RTOBL*mp, (j, k), h*)

**S**DCRTOBLLO *mp* = ∑*(j, k), h* (RTOBLLO*mp, (j, k), h*)

**S**DCDAOPT *mp* = ∑*(j, k), h* (OPT*mp, (j, k), h*)

**S**DCDAOBL *mp* = ∑*(j, k), h* (DAOBL*mp, (j, k), h*)

**S**DCOPTS *mp* = ∑*(j, k), h* (OPTS*mp, (j, k), h*)

**S**DCOBLS *mp* = ∑*(j, k), h* (OBLS*mp, (j, k), h*)

**S**DCOPTP *mp* = ∑*(j, k), h* (OPTP*mp, j, h*)

**S**DCOBLP *mp* = ∑*(j, k), h* (OBLP*mp, (j, k), h*)

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

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| SDCRSCP *cp* | $ | *Securitization Default Charge Ratio Share per Counter-Party*—The Counter-Party’s pro rata portion of the total Securitization Charges for a month. |
| TSDCMA | $ | *Total Securitization Default Charge Monthly Amount*—The amount ERCOT determines must be collected for the month in order to timely repay the Securitization Default Balance. |
| SDCMMARS *cp* | None | *Securitization Default Charge Maximum MWh Activity Ratio Share*—The Counter-Party’s pro rata share of Maximum MWh Activity. |
| SDCMMA *cp* | MWh | *Securitization Default Charge Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction for the reference month. |
| SDCMMATOT | MWh | *Securitization Default Charge Maximum MWh Activity Total*—The sum of all Counter-Party’s Maximum MWh Activity. |
| RTMG *mp, p, r, i* | MWh | *Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| SDCRTMG *mp* | MWh | *Securitization Default Charge Real-Time Metered Generation per Market Participant*—The monthly sum in the reference month of Real-Time energy produced by Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTDCIMP *mp, p, i* | MW | *Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| SDCRTDCIMP *mp* | MW | *Securitization Default Charge Real-Time DC Import per Market Participant*—The monthly sum in the reference month of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party. |
| RTAMLEXSECM *mp, p, i* | MWh | *Real-Time Adjusted Metered Load Excluding Load Exempt from Sub M per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML), excluding Load that is exempt from Securitization Default Charges pursuant to the Declaratory Order entered by the Public Utility Commission of Texas (PUCT) in PUCT Docket No. 56122, Petition of Electric Reliability Council of Texas, Inc. for Expedited Declaratory Order Regarding Public Utility Regulatory Act Chapter 39, Subchapter M, at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| SDCRTAML *mp* | MWh | *Securitization Default Charge Real-Time Adjusted Metered Load per Market Participant*—The monthly sum in the reference month of the AML, excluding Load exempt from Securitization Default Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56122, represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTQQES *mp, p, i* | MW | *QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| SDCRTQQES *mp* | MWh | *Securitization Default Charge QSE-to-QSE Energy Sale per Market Participant*—The monthly sum in the reference month of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTQQEP *mp, p, i* | MW | *QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE. |
| SDCRTQQEP *mp* | MWh | *Securitization Default Charge QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum in the reference month of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| DAES *mp, p, h* | MW | *Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*’s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE. |
| SDCDAES *mp* | MWh | *Securitization Default Charge Day-Ahead Energy Sale per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*’s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| DAEP *mp, p, h* | MW | *Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*’s cleared DAM Energy Bids at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.   |  | | --- | | ***[NPRR1188: Replace the definition above with the following upon system implementation:]***  *Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*’s DAM Energy Bids and Energy Bid Curves, cleared in the DAM, at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE. | |
| SDCDAEP *mp* | MWh | *Securitization Default Charge Day-Ahead Energy Purchase per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*’s cleared DAM Energy Bids, where the Market Participant is a QSE assigned to the registered Counter-Party.   |  | | --- | | ***[NPRR1188: Replace the definition above with the following upon system implementation:]***  *Securitization Default Charge Day-Ahead Energy Purchase per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*’s DAM Energy Bids and Energy Bid Curves, cleared in the DAM, where the Market Participant is a QSE assigned to the registered Counter-Party. | |
| RTOBL *mp, (j, k), h* | MW | *Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*’s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE. |
| SDCRTOBL *mp* | MWh | *Securitization Default Charge Real-Time Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*’s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party. |
| RTOBLLO *q, (j, k)* | MW | *Real-Time Obligation with Links to an Option per QSE per pair of source and sink*⎯The total MW of the QSE’s PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour. |
| SDCRTOBLLO *q, (j, k)* | MW | *Securitization Default Charge Real-Time Obligation with Links to an Option per QSE per pair of source and sink*⎯The monthly total in the reference month of Market Participant *mp*’s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party. |
| OPT *mp, (j, k), h* | MW | *Day-Ahead Option per Market Participant per source and sink pair per hour*⎯The number of Market Participant *mp*’s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder. |
| SDCDAOPT *mp* | MWh | *Securitization Default Charge Day-Ahead Option per Market Participant*⎯The monthly total in the reference month of Market Participant *mp*’s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| DAOBL *mp, (j, k), h* | MW | *Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*’s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder. |
| SDCDAOBL *mp* | MWh | *Securitization Default Charge Day-Ahead Obligation per Market Participant*⎯The monthly total in the reference month of Market Participant *mp*’s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OPTS *mp, (j, k), a, h* | MW | *PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| SDCOPTS *mp* | MWh | *Securitization Default Charge PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*’s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OBLS *mp, (j, k), a, h* | MW | *PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| SDCOBLS *mp* | MWh | *Securitization Default Charge PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*’s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OPTP *mp, (j, k), a, h* | MW | *PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| SDCOPTP *mp* | MWh | *Securitization Default Charge PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*’s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| OBLP *mp, (j, k), a, h* | MW | *PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*’s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder. |
| SDCOBLP *mp* | MWh | *Securitization Default Charge PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*’s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party. |
| SDCWSLTOT *mp* | MWh | *Securitization Default Charge Metered Energy for Wholesale Storage Load at bus per Market Participant*⎯The monthly sum in the reference month of Market Participant *mp*’s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL. |
| MEBL *mp, r, b* | MWh | *Metered Energy for Wholesale Storage Load at bus*⎯The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*. |
| *cp* | none | A registered Counter-Party. |
| *mp* | none | A Market Participant that is a QSE or CRR Account Holder with activity in the reference month, except for a Market Participant exempt from Securitization Default Charges pursuant to the Final Order entered by the PUCT in PUCT Docket No. 52321, Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M. Defaulted Market Participants with market activity in the reference month are included in the calculation. |
| *j* | none | A source Settlement Point. |
| *k* | none | A sink Settlement Point. |
| *a* | none | A CRR Auction. |
| *p* | none | A Settlement Point. |
| *i* | none | A 15-minute Settlement Interval. |
| *h* | none | The hour that includes the Settlement Interval *i*. |
| *r* | none | A Resource. |

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

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

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

**ERCOT Nodal Protocols**

**Section 22**

**Attachment E: Notification of Suspension of Operations**

**TBD**

**Notification of Suspension of Operations of a Generation Resource or Energy Storage Resource**

This Notification is required for providing notification of any Generation Resource or Energy Storage Resource (ESR) suspension lasting greater than 180 days. Information may be inserted electronically to expand the reply spaces as necessary.

The Notification must be signed, notarized and delivered to ERCOT. Delivery may be accomplished via email to [MPRegistration@ercot.com](mailto:MPRegistration@ercot.com) (if a scanned copy) or via facsimile (Attention: Market Participant Registration) at (512) 225-7079.

ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

**Part I:**

Resource Entity:

DUNS Number:

Resource Site Name:

Resource Site Location (County):

Unit Name(s):

Resource Name(s) (Unit Code/Mnemonic):

ESI ID:

Seasonal Net Max Sustainable Rating – Summer (MW):

Seasonal Net Minimum Sustainable Rating – Summer (MW):

Transmission Facilities that will be deactivated or removed from service as part of the suspension of operations of the unit(s):

**Part II:**

As of [Date],[[1]](#footnote-1) the Resource(s) will be limited or unavailable for Dispatch by ERCOT because Resource Entity will [check one]:

decommission and retire the Resource(s) permanently for a reason other than a Forced Outage,[[2]](#footnote-2)

suspend operation on a year-round basis (*i.e.*, mothball) and begin operation on a seasonal basis with a Seasonal Operation Period that begins on [Date] and ends on [Date]. The Seasonal Operation Period must be inclusive of June 1 through September 30,

temporarily suspend operation (*i.e.*, mothball) of the Resource(s) for a period of not less than     months and not greater than     months due to some reason other than a Forced Outage, or

indefinitely suspend operation (*i.e.*, mothball) of the Resource(s).

On [Date], the Resource experienced a Forced Outage. As a result of the Forced Outage, the Resource Entity intends to [check one]:

decommission and retire the Resource(s) permanently,2

temporarily suspend operation of the Resource(s), with an estimated return date of [Date], or

indefinitely suspend operation (*i.e.*, mothball) of the Resource(s).

Check if applicable:  Resource Entity believes that this Resource(s) is inoperable due to emissions limitations or not being repairable.

Operational and Environmental Limitations (check and describe all that apply):

(a) Operational:

Maximum annual hours of operation:

Maximum annual MWhs:

Maximum annual starts:

Other:

(b) Environmental:

Maximum annual NOx emissions:

Maximum annual SO2 emissions:

Other:

**Part III:**

Estimated RMR Fuel Adder ($/MMBtu):

Proposed Initial Standby Cost ($/hr):

I understand and agree that this Notification is not confidential and does not constitute Protected Information under the ERCOT Protocols.

I hereby certify that the proposed, estimated Fuel Adder, Standby Costs, and attached budget are accurate at the time of submittal, necessary, and do not exceed fair-market value.

The undersigned certifies that I am an officer or executive of Resource Entity, that I am authorized to execute and submit this Notification on behalf of Resource Entity, and that the statements contained herein are true and correct.

Name:

Title:

Date:

**ERCOT Nodal Protocols**

**Section 22**

**Attachment H: Notification of Change of Resource Designation**

**TBD**

**Notification of Change of Resource Designation**

This Notification is for changing a Generation Resource or Energy Storage Resource (ESR) designation in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary.

The Notification must be signed, notarized and delivered to ERCOT. Delivery may be accomplished via email to [MPRegistration@ercot.com](mailto:MPRegistration@ercot.com) (if a scanned copy) or via facsimile (Attention: Market Participant Registration) at (512) 225-7079. ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

Resource Entity:

DUNS No.:

Resource(s) [plant and unit number(s)]

Resource(s) is currently [check one]

decommissioned and retired

under a Reliability Must-Run (RMR) Agreement

mothballed under a Seasonal Operation Period

mothballed

As of        [date], Resource Entity will change the Resource(s) designation to [check one]

operational (for a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period, selecting this option means that the Generation Resource or ESR is returning to year round service)

mothballed (a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period may not select this option, and must instead use the Section 22, Attachment E, Notification of Suspension of Operation form to change to a different mothballed status)

decommissioned and retired permanently[[3]](#footnote-3) (a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period may not select this option and must instead use the form in Section 22, Attachment E to be designated as decommissioned)

Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period, updating start date or end date of Seasonal Operation Period

As of        [date], a Mothballed Generation Resource or Mothballed ESR will change its Seasonal Operation Period as follows:

change start date of Seasonal Operation Period from       to

change end date of Seasonal Operation Period from       to

The undersigned certifies that I am an officer of Resource Entity, that I am authorized to execute and submit this Notification on behalf of Resource Entity, and that the statements contained herein are true and correct.

Name:

Title:

Date:

STATE OF \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

COUNTY OF \_\_\_\_\_\_\_\_\_\_\_\_\_

Before me, the undersigned authority, this day appeared \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

“I am an officer of \_\_\_\_\_\_\_\_\_\_\_\_\_\_, I am authorized to execute and submit the foregoing Notification on behalf of \_\_\_\_\_\_\_\_\_\_\_\_\_\_, and the statements contained in such Notification are true and correct.”

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the \_\_\_\_\_ day of \_\_\_\_\_\_\_\_\_\_\_\_, 20\_\_.

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Notary Public, State of \_\_\_\_\_\_\_\_\_\_\_

My Commission expires \_\_\_\_\_\_\_\_\_\_

**ERCOT Nodal Protocols**

**Section 22**

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

**TBD**

**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, an Energy Storage Resource (ESR), or a Settlement Only Generator (SOG) in a Private Use Network shall use this form to provide ERCOT with information required by ERCOT Protocol Section 10.3.2.4, Reporting of Net Generation Capacity. This form must be submitted to ERCOT by February 1 of each year. ERCOT shall treat this information as Protected Information in accordance with paragraph (1)(x) of Section 1.3.1.1, Items Considered Protected Information.

Please fill out this form electronically, print and sign. The form can be sent to ERCOT via email to [MPRegistration@ercot.com](mailto:MPRegistration@ercot.com) (.pdf), via facsimile to (512) 225-7079, or via mail to ERCOT, Attention: Market Participant Registration, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744.

Date of Notice:

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

Facility Name:

In the table below, enter the incremental forecasted changes in net generation capacity (in Megawatts) available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and year-on-year changes as of May 31 for the next 10 subsequent years. The capacity forecasts should account for changes in ESR capacity (for both charging and discharging), 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 or storage associated with the capacity changes reported above.

|  |
| --- |
|  |
|  |
|  |
|  |

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

Signature of Authorized Signatory:

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

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

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

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

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| [NPRR995: Replace Section 22, Attachment L above with the following upon system implementation:]  **Declaration of Private Use Network Net Generation Capacity Availability**  A Private Use Network is an electric network connected to the ERCOT Transmission Grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation). A Resource Entity that represents a Generation Resource, an Energy Storage Resource (ESR), 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, 8000 Metropolis Drive (Building E), Suite 100, Austin, Texas 78744.  Date of Notice:  Resource Entity:       DUNS Number:  Facility Name:  In the table below, enter the incremental forecasted changes in net generation capacity (in Megawatts) available to the ERCOT Transmission Grid for May 31 of the previous calendar year to May 31 of the current calendar year, and year-on-year changes as of May 31 for the next 10 subsequent years. The capacity forecasts should account for changes in ESR capacity (for both charging and discharging), 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 or storage associated with the capacity changes reported above.   |  | | --- | |  | |  | |  | |  |   By signing below, I certify that I am authorized to execute and submit this Notice on behalf of the above Resource Entity, and that the data and statements contained herein are true and correct to the best of my knowledge.  Signature of Authorized Signatory:  Name: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Title: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Phone: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_ |

**ERCOT Nodal Protocols**

**Section 22**

**Attachment N: Standard Form Must-Run Alternative Agreement**

**TBD**

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| NPRR885: Insert Section 22 Attachment N below upon system implementation:]  Standard Form Must-Run Alternative  Supplement to the Market Participant Agreement  Between  (Name of Participant)  and  Electric Reliability Council of Texas, Inc.  This Must-Run Alternative Service Supplement to the Market Participant Agreement (“Agreement”), effective as of the \_\_\_\_\_\_\_\_\_\_ day of \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_, \_\_\_\_\_\_\_\_\_\_\_ (“Effective Date”), is entered into by and between [insert Participant’s name], a [insert business Entity type and state] (“Participant”) and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation (“ERCOT”).  Recitals  WHEREAS:  A. Participant is a Qualified Scheduling Entity (QSE) as defined in the ERCOT Protocols, has executed a Standard Form Market Participant Agreement (“Market Participant Agreement”) with ERCOT, and intends to provide Must-Run Alternative (MRA) Service;  B. ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;  C. On \_\_\_\_\_\_\_, 20\_\_, ERCOT issued a Request for Proposals (“MRA RFP”) seeking offers from QSEs able to provide MRA Service;  D. Participant submitted an offer to provide MRA Service in response to the RFP that satisfies the requirements for MRA Service, as set forth in the ERCOT Protocols;  E. Pursuant to PUC Substantive Rule 25.502, the ERCOT Board of Directors has approved a recommendation to enter into this Agreement;  F. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.  Agreements  NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the “Parties”) hereby agree as follows:  Section 1. MRA Terms.  A. Start Date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_, 20\_\_\_\_\_.  B. Stop Date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_, 20\_\_\_\_\_.  C. MRA: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_.  D. Description of MRA or, if an aggregation, MRA Sites [*including location(s), type(s) of unit, etc.]:* \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_.  E. MRA Information  (1) MRA Contracted Capacity, Target Availability and Standby Price for each MRA Contracted Month   |  |  |  |  |  |  | | --- | --- | --- | --- | --- | --- | | **MRA Contracted Month - Year** | **MRA Contracted Hours (whole Hours Ending (HEs))** | **Capacity (MW per hr)** | **Days of Week** | **Target Availability (%)** | **Standby Price ($/MW per hr)** | |  |  |  |  |  |  | |  |  |  |  |  |  | |  |  |  |  |  |  |   (2) MRA Contributed Capital Expenditures   |  |  | | --- | --- | | **Month - Year** | **Capital Expenditure ($)** | |  |  | |  |  | |  |  |   (3) Data for MRA deployment event compensation  (a) Proxy Fuel Consumption (MMBtu/Deployment Event): \_\_\_\_\_\_\_\_\_\_, or  (b) Event Deployment Price ($/Deployment Event): \_\_\_\_\_\_\_\_\_\_  (c) Ramp period or start-up time (hrs): \_\_\_\_\_\_\_\_\_  (4) Data needed for variable compensation  (a) Proxy Heat Rate (MMBtu/MWh): \_\_\_\_\_\_\_\_\_\_, and/or  (b) Variable Price ($/MWh): \_\_\_\_\_\_\_\_\_\_  (5) Proxy Fuel Adder Price ($/MMBtu): \_\_\_\_\_\_\_\_\_\_  F. For Thermal and Non-Thermal Generators, including ESRs, (Transmission or Distribution Connected)  (1) Delivery Point:\_\_\_\_\_\_\_  (2) Revenue Meter Location (Use Resource ID):\_\_\_\_\_\_\_\_\_\_  ***[If multiple MRAs awarded to a single QSE, duplicate Sections 1(A)-1(F) for each MRA here]***  Section 2. Additional Terms.  A. The terms and conditions of the Market Participant Agreement between Participant and ERCOT remain in full force and effect.  B. Participant agrees to make available for ERCOT’s use the MRA Service described in Section I of this Agreement, in accordance with and subject to ERCOT Protocols, the Market Participant Agreement, and the MRA RFP, all of which are hereby incorporated by reference.  C. Term of Agreement  (1) This Agreement is effective beginning on the Effective Date, subject to paragraph 2(F) below.  (2) The Term of this Agreement begins at 0000 hours on the Start Date and ends at 2400 hours on the Stop Date.  D. Except as provided in paragraphs 2(E) and 2(F) below, this Agreement terminates upon the completion of all obligations under the terms of this Agreement, provided that the Term of this Agreement may be extended for a period of up to 90 days if, in ERCOT’s sole discretion, such an extension is necessary. ERCOT shall provide written notice of such an extension no later than 30 days before the date the extension is to begin.  E. ERCOT, at its sole discretion, may terminate the Parties’ obligations under this Agreement with respect to any MRA listed in Section 1 above at any time upon 90 days’ notice if it determines that the MRA Service provided by the MRA is no longer necessary.  If more than one MRA is listed in Section 1, the Parties’ obligations under this Agreement will continue with respect to any MRA not terminated pursuant to this paragraph.  F. Participant may, at its option, immediately terminate this Agreement upon the failure of ERCOT to continue to be certified by the PUCT as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151.  G. If ERCOT has awarded offers to multiple QSEs for MRA Service in response to a single MRA RFP, this Agreement will be effective only upon written confirmation by ERCOT to Participant that ERCOT has secured fully executed MRA Agreements from each QSE with an awarded offer. This confirmation is a condition precedent to performance of any obligation under this Agreement.  H. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.  I. Payments to Participant for MRA Service shall be made based on the MRA offers awarded by ERCOT and in accordance with the ERCOT Protocols applicable to MRA Service.  J. Automatic Default. The occurrence of either of the following shall constitute an automatic Default by Participant under this Agreement:  (1) The MRA or one or more MRA Sites is abandoned without an intention to return to operation during the term of the MRA Agreement or approval by ERCOT of a substitute MRA or MRA Site in accordance with Protocol Section 3.14.4.3, MRA Substitution; or  (2) Three or more unexcused Misconduct Events, as described in Protocol Section 3.14.4.8, MRA Misconduct Events, occur during the term of the MRA Agreement.  K. Other Default Events. A material failure by Participant to comply with the ERCOT Protocols governing MRA Service, the terms of this Agreement, or the MRA RFP shall constitute a Default unless cured within fourteen (14) Business Days after ERCOT gives notice of the material breach to Participant.  L. Remedies for Default. In addition to ERCOT’s remedies for Default described in the Market Participant Agreement, ERCOT may, in its sole discretion, terminate this Agreement upon seven days’ written notice in the event of Participant’s Default.  M. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.  SIGNED, ACCEPTED, AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.  ***Electric Reliability Council of Texas, Inc.:***  By: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Name: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Title: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  ***Participant:***  By: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Name: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Title: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Date: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Market Participant Name: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_  Market Participant DUNS: \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_ |

**ERCOT Nodal Protocols**

**Section 22**

**Attachment P: Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints**

**TBD**

# 1. Purpose

Section 6.5.7.1.11, Transmission Network and Power Balance Constraint Management, requires the Public Utility Commission of Texas (PUCT) to approve ERCOT’s methodology for establishing caps on the Shadow Prices for transmission constraints and the Power Balance constraint. Additionally, PUCT must also approve the values (in $/MWh) for each of the Shadow Price caps.

The effect of the Shadow Price cap for transmission network constraints is to limit the cost calculated by the Security-Constrained Economic Dispatch (SCED) optimization to resolve an additional MW of congestion on a transmission network constraint to the designated maximum Shadow Price for that transmission network constraint. The effect of the Shadow Price cap for the Power Balance Constraint is to limit the cost calculated by the SCED optimization when the instantaneous amount of generation to be dispatched does not equal the instantaneous demand of the ERCOT system. In this case, the cost calculated by SCED to resolve either the addition or reduction of one MW of dispatched generation on the power balance constraint is limited to the maximum Shadow Price for the power balance constraint, which is also referred to as the Power Balance Penalty.

The maximum Shadow Prices for the transmission network constraints and the power balance constraint directly determine the Locational Marginal Prices (LMPs) for the ERCOT Real-Time Market (RTM) in the cases of constraint violations.

This Attachment describes:

* the PUCT-approved methodology that the ERCOT staff will use for determining the maximum system-wide Shadow Prices for transmission network constraints and for the power balance constraint, and
* the PUCT-approved Shadow Price caps and their effective date.

**2. Background Discussion**

The term Shadow Price as used in a constrained optimization problem in economics, is usually defined as the change in the objective value of the optimal solution of the optimization problem obtained by changing each constraint, one-at-a-time, by one unit. In the SCED process the objective function to be minimized by the SCED optimization engine is the total system dispatch cost required to maintain the system power balance and to resolve congestion of the transmission network as specified in the transmission constraint input set. The term Shadow Price is used in the context of individual constraints, whether a transmission network constraints or power balance constraint. Consistent with the definition of the Shadow Price, in a minimization problem, such as the SCED, the Shadow Prices for the transmission constraints are different for each transmission constraint and they are positive $/MW amounts defined as increase of the system dispatch costs if a transmission line limit is decreased by one MW. The Shadow Price for the Power Balance constraint represents system costs for serving the last MW of load. The Power Balance Penalty can be either positive (if the system requires additional generation) or negative (if the system requires a reduction in generation). If a constraint is not binding, meaning the constraint has excess capability under the given system conditions, the Shadow Price of the constraint is $0.00/MWh. On the other hand, if the constraint is binding, meaning it is limiting because the system conditions are such that the constraint limit is exactly met by the SCED selected dispatch pattern, the constraint Shadow Price is a non-zero $/MW value and when the maximal Shadow Price (i.e. the Shadow Price cap) is reached the constraint will be violated without further increases in the constraint Shadow Price.

In the context of the SCED optimization, the Shadow Prices give rise to the application of a transmission penalty cost and a power balance penalty cost in the SCED objective function that results in an increase in the total system dispatch cost. On the other hand, the transmission network constraint Shadow Prices and the Power Balance Shadow Price directly determine the LMPs (in $/MWh) calculated in the SCED. The LMPs will be limited because of the Shadow Price cap amounts, expressed in $/MWh.

For the network transmission constraints, the Shadow Price Cap may vary for each constraint, may be a unique value applicable to all constraints, or may be values unique to subsets of the full constraint set. For the Power Balance constraint, the Shadow Price Cap may be a single value or a value given as a function of the amount of the power balance mismatch (instantaneous generation to be dispatch minus instantaneous demand) in MW.

|  |
| --- |
| ***[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  For the network transmission constraints, the Shadow Price Cap may vary for each constraint, may be a unique value applicable to all constraints, or may be values unique to subsets of the full constraint set. For the Power Balance constraint, the Shadow Price Cap is a single value. |

**3. Elements for Methodology for Setting the Network Transmission System-Wide Shadow Price Caps**

**3.1 Congestion LMP Component**

The LMPs at Electrical Buses are calculated as follows:

Where:

is LMP at Electrical Bus *EB*

is System Lambda (Shadow Price of power balance)

is Shift Factor for Electrical Bus *EB* for transmission *line*

is Shadow Price for transmission *line.*

Note that the Shadow Prices for congested transmission lines are positive, otherwise they are equal zero. The Shift Factors for Electrical Buses on one side of transmission line are negative and for Electrical Buses on the other side of transmission line are positive.

The congestion component of Electrical Bus LMP is:

and it can be positive or negative depending on sign of Shift Factors. The congestion component of LMP represents a price incentive to generation units connected at that Electrical Bus to increase or decrease power output to manage network congestion. Note that only marginal units (i.e. units that are able to move, not those dispatched at min/max dispatch limits to resolve other constraints or to provide energy to the system) can participate in resolving network congestion and determining the System Lambda for a particular iteration of SCED.

The optimal dispatch from both system (minimal congestion costs) and unit (maximal unit profit) prospective is determined by condition:

.

The generation unit response to pricing signal will result in line power flow reduction in amount:

These relationships are illustrated at the following figure:



**3.2 Network Congestion Efficiency**

The following three elements of network congestion management determine the efficiency of a generating unit participation (as defined above):

* + Line power flow contribution
  + LMP congestion component
  + Unit power output adjustment .

The line power contribution is determined by its Shift Factor directly. It may be established that generating units with Shift Factors below specified threshold (10%) are not efficient in network congestion.

The LMP congestion component is the main incentive controlling generating unit dispatch. It is determined by Shift Factors and Shadow Prices for transmission constraints:

.

Generating units with small Shift Factors (i.e. below Shift Factor threshold) will not be as effective in resolving constraints as will generation units with higher shift factors on the constraint. If there are no efficient generating units then the Shadow Price must be increased to get enough contribution from inefficient units. Therefore, high Shadow Prices indicate inefficient congestion management.

The maximal value of LMP congestion component directly limits the transmission congestion costs:

.

The efficiency of a generating unit contribution can be determined by maximal value of LMP congestion component (say $500/MWh). The maximal Shadow Price for transmission constraint can be established by Shift Factor efficiency threshold and maximal LMP congestion component as follows:

.

The maximal unit power output adjustment will be determined by condition:

**3.3 Shift Factor Cutoff**

Note: This Shift Factor cutoff is not related to above Shift Factor efficiency threshold used for determination of maximal Shadow Price.

Some generating units (Generation Resources and ESRs) can be excluded from network congestion management by ignoring their contribution in line power flows. Note that this exclusion cannot be performed physically, i.e. all units will always contribute to line power flows according to their Shift Factors. Therefore, the Shift Factor cutoff introduces an additional approximation into line power flow modeling.

Since the effect of the Shift Factors below the cut off on the overload are ignored in the optimization, any Shift Factor cutoff will cause additional re-dispatch of the remaining generating units (Generation Resources and ESRs) participating in the management of congestion on the constraint. I.e. Generation Resources and ESRs with a Shift Factor above the cut off will have to be moved more to account for the increase in overload caused by increasing generation of an inexpensive Resource with positive Shift Factor below cut off and decreasing generation of an expensive Resource with negative Shift Factor below cut off.

The Shift Factor cutoff will cause mismatch between optimized line power flow and actual line power flow that will happen when dispatch Base Points are deployed. This mismatch can degrade the efficiency of congestion management.

The Shift Factor cutoff can reduce volume of Shift Factor data and filter out numerical errors in calculating Shift Factors. Currently the default value of Shift Factor cut off is 0.0001) and is implemented at the Energy Management System (EMS) to reduce the amount of data transferred to MMS. Any threshold above that level will cause a distortion of congestion management process.

**3.4 Methodology Outline**

The methodology for determination of maximal Shadow Prices for transmission constraints could be based on the following setting:

(a) Determine Shift Factor efficiency threshold (default x%)

(b) Determine maximal LMP congestion component (default $y/MWh)

(c) Calculate maximal Shadow Price for transmission constraints:

(d) Determine Shift Factor cutoff threshold (default z%)

(e) Evaluate settings on variety of SCED save cases.

**3.5 Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED**

The Generic Transmission Shadow Price Caps noted below will be used in SCED unless ERCOT determines that a constraint is irresolvable by SCED. The methodology for determining and resolving an insecure state within SCED (i.e. SCED Irresolvable) is defined in Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm, whereas the subsequent trigger condition for the determination of that constraint’s Shadow Price Cap is described in Section 3.6, Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED.

**Generic Transmission Constraint (GTC) Shadow Price Caps in SCED**

* Base Case/Voltage Violation: $5,251/MW
* N-1 Constraint Violation
  + Greater than 200 kV: $4,500/MW
  + 100 kV to 200 kV: $3,500/MW
  + Less than 100 kV: $2,800/MW

***3.5.1 Generic Transmission Constraint Shadow Price Cap in SCED Supporting Analysis***

Figure 1 is a contour map that shows the relationship between the level of the constraint shadow price cap, the offer price difference of the marginal units deployed to resolve a constraint, and the shift factor difference of the marginal units deployed to resolve a constraint.[[4]](#footnote-4)

Figure 1

Figure 2 is a projection of Figure 1 onto the x-axis (i.e., looking at it from the top). These two figures focus on constraint shadow price cap levels, and do not consider the interaction with the power balance constraint penalty factor, which is further discussed in association with Figure 4.

**Figure 2**

Figures 1 and 2 show that:

* For a constraint shadow price cap of $5,251/MW
  + Marginal units with an o*ffer price difference* of $52.51/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  + Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 2.9%.
* For a constraint shadow price cap of $4,500/MW
  + Marginal units with an *offer price difference* of $45/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  + Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 3.4%.
* For a constraint shadow price cap of $3,500/MW
  + Marginal units with an *offer price difference* of $35/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  + Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 4.3%.
* For a constraint shadow price cap of $2,800/MW
  + Marginal units with an *offer price difference* of $28/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  + Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 5.35%.

Figure 3 shows the maximum offer price difference of the marginal units that will be deployed to resolve congestion with each of the proposed shadow price cap values as a function of the shift factor difference of the marginal units.

**Figure 3**

For example, with a shift factor difference of the marginal units of just 2%, the maximum offer price difference of the marginal units that will be deployed to resolve the constraint is $56, $70, $90 and $105.02/MWh for constraint shadow price cap values of $2,800, $3,500, $4,500 and $5,251/MW, respectively. Similarly, for with a shift factor difference of the marginal units of 60%, the maximum offer price difference of the marginal units that will be deployed to resolve the constraint is $1,680, $2,100, $2,700 and $3,150.60/MWh for constraint shadow price cap values of $2,800, $3,500, $4,500 and $5,251/MW, respectively.

**In some circumstances these constraint shadow price cap values may preclude the deployment of an offer at the System-Wide Offer Cap (SWCAP).** However, it is not possible in the nodal design to establish constraint shadow price caps at a level that will always accept an offer at SWCAP and still produce pricing outcomes that remain within reasonable bounds of subsection (g)(6) of P.U.C. Subst. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region. For example, taking the case above where the shift factor difference of the marginal units is just 2%, a constraint shadow price cap of $250,000/MW would be required to deploy $5,000/MWh offers to resolve the congestion (assuming an offer price of zero for the marginal constrained-down unit). In this case, for nodes with a higher shift factor relative to the constraint (regardless of whether the nodes are generation or load nodes), the resulting LMP would be significantly higher than a $5,000/MWh SWCAP if the constraint was irresolvable. For example, a node with a shift factor of -50% would have an LMP with a congestion component of $125,000/MWh from just this one constraint, and even higher if multiple constraints are binding. In contrast, with a $5,251/MW shadow price cap, the congestion component of the LMP of the node with a shift factor of -50% would be $2,625.50/MW for just this one constraint.

**The LMP at an individual node, hub or load zone can exceed the SWCAP in some circumstances**. This is most likely to occur when there are one or more irresolvable constraints on the system *and* when overall dispatchable supply on the system is tight. Relatively speaking, it is more likely that individual node prices will exceed the SWCAP than hubs or load zones, but it is possible that hub or load zone prices could exceed the SWCAP. It is not possible in the nodal system to assign constraint shadow price caps and power balance penalty factor values that achieve the desired reliability and efficiency objectives and ensure that all LMPs remain within the bounds of the SWCAPs under all circumstances.

Operationally once ERCOT reaches the shadow price cap, ERCOT may use the following method to manage congestion. Steps that may be taken by ERCOT operations to resolve congestion when the transmission constraint is violated in SCED after the Shadow Price reaches the shadow price cap include:

* Formulating a mitigation plan which may include
* Transmission reconfiguration (switching)
* Load rollover to adjacent feeders
* Load shed plans
* Redistribution of ancillary services to increase the capacity available within a particular area.
* Commitment of additional units.
* Re-dispatching generation through over-riding High Dispatch Limit (HDL) and Low Dispatch Limit (LDL) in accordance with paragraph (3)(g) of Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm.

**3.6 Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED**

ERCOT Operations is required to resolve security violations on the ERCOT Grid as described in Section 6, Adjustment Period and Real-Time Operations, and the associated Nodal Operating Guides and ERCOT will utilize the SCED application or direct actions on the transmission network and among Generation Resources and Energy Storage Resources (ESRs), as needed, to resolve security violations. With regard to SCED operations, if a security violation on a constraint occurs, ERCOT will determine whether or not this constraint violation should be deemed to be irresolvable by online Generation Resource and ESR dispatch by the SCED application. ERCOT will use the methodology described in this section to determine the Shadow Price Cap for a constraint that is deemed irresolvable pursuant to Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, below. For each of these constraints this Shadow Price Cap will be used by the SCED application in place of the generic cap specified by Section 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, until ERCOT deems the constraint resolvable by SCED. ERCOT shall provide the market 30 days notice before deeming the constraint resolvable by SCED. Upon deeming the constraint resolvable by SCED, the Shadow Price Cap for the constraint shall be determined pursuant to Section 3.5.

***3.6.1 Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED***

The methodology for determining and resolving an insecure state within SCED is defined in Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm. ERCOT shall modify the Shadow Price Cap for a transmission network constraint that is consistently irresolvable by SCED if either of the following two conditions are true. Intervals with manual overrides performed as a result of SCED not resolving the congestion, shall be included:

1. A constraint violation is not resolved by the SCED dispatch or overridden for more than two consecutive hours on more than 4 consecutive Operating Days; or
2. A constraint violation is not resolved by the SCED dispatch for more than a total of 20 hours in a rolling thirty-day period.

On the Operating Day during which ERCOT deems a network transmission constraint to have met the trigger conditions, ERCOT shall identify the following Generation Resources and/or ESRs:

1. The Generation Resource or ESR with the lowest absolute value of the negative shift factor impact on the violated constraint (this resource is referred as Resource C in the Shadow Price Cap calculation below); and,
2. The Generation Resource or ESR with the highest absolute value of the negative shift factor on the violated constraint (this resource is referred to as Resource D in the designation of the net margin Settlement Point Price described below).

When determining Resources C and D above, ERCOT shall ignore all Generation Resources and ESRs that have a shift factor with an absolute value of less than 0.02 impact on the irresolvable constraint.

***3.6.2 Methodology for Setting the Constraint Shadow Price Cap for a Constraint that is Irresolvable in SCED***

The Shadow Price Cap for a constraint that has met the trigger conditions described in Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, and the Shadow Price Cap for any constraint that has the same overloaded transmission element and direction as a constraint that has met the trigger conditions, will be determined as follows.

The Shadow Price Cap on the constraint that has met the trigger conditions described in Section 3.6.1, will be set to the minimum of E or F as follows:

1. The value of the Generic Shadow Price Cap as determined in Section 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, and
2. The Maximum of the either the largest value of the Mitigated Offer Cap (MOC) for Resource C, as determined above, divided by the absolute value of its shift factor impact on the constraint or$2000 per MW.

This calculation is performed one time in the Operating Day during which the trigger conditions described in Section 3.6.1 have been met and, subject to the value of the constraint net margin described below, this Shadow Price Cap will remain in effect for the shorter of the remainder of the calendar year or the remainder of the month in which the constraint is determined to be resolvable by SCED.

When the value of a constraint that has met the trigger conditions described in Section 3.6.1 accumulates a net margin, as determined in Section 3.6.3, The Constraint Net Margin Calculation for Constraints that Have Met the Trigger Conditions in Section 3.6.1, below, that exceeds $95,000/MW at any time during the remainder of the calendar year following the determination that the constraint is irresolvable by SCED, the Shadow Price Cap for this, and for all constraints that have the same overloaded transmission element and direction as the constraint in the next Operating Day will be set to the minimum of either $2,000/MWh or G, below, for the remainder of the calendar year:

1. The Maximum of either the largest value of the MOC for Resource C, as determined above, divided by the absolute value of its shift factor on the constraint or the currently effective Low System-Wide Offer Cap (LCAP) pursuant to subsection (g) of P.U.C. Subst. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region.

When a constraint meets the trigger condition described in Section 3.6.1 and accumulates a net margin that exceeds $95,000/MW as described in Section 3.6.2, ERCOT shall:

1. As soon as practicable, but not more than ten (10) business days after the triggers are met, review transmission outages and recall outages that are contributing to overloading the constraint(s), if feasible.

2. As soon as practicable, but not more than thirty (30) days after the triggers are met, review and develop Remedial Action Plans (RAPs) or Temporary Outage Action Plans (TOAPs) to mitigate congestion on the affected constraint(s), if feasible. To the degree that a RAP or TOAP can be developed, ERCOT shall implement it through an Emergency Database Load, if necessary to avoid delay in addressing the congestion.

3. As soon as practicable, but not more than ninety (90) days after the triggers are met, review and develop or identify one or more Special Protection Systems or transmission proposal(s) to alleviate the risk of future congestion on the affected constraint(s), if feasible, so long as the proposed solution produces an overall reduction of congestion on the ERCOT system.

4. Perform a detailed review of the constraint(s) that is irresolvable by SCED, and in the next annual Regional Transmission Plan, identify projects that will mitigate the risk of future recurrence of the condition, if any.

Additionally, at the end of the calendar year, for all constraints that have a Shadow Price cap set in accordance with this section, ERCOT will:

* Again determine Resource C and D, as described in item C and D above; and,
* Reset the Shadow Price Cap for each of the SCED irresolvable constraints to the minimum of E or F above for that constraint. These changes shall be become effective in January of the next year.
* Reset the Shadow Price Cap for each constraint determined to be resolvable by SCED to the appropriate generic value as defined in Section 3.5.

The Independent Market Monitor (IMM) may initiate re-evaluation of the maximum Shadow Price of the constraint if it is identified that the constraint can be resolvable. This will reset the constraint net margin calculation.

***3.6.3 The Constraint Net Margin Calculation for Constraints that Have Met the Trigger Conditions in Section 3.6.1***

Each constraint that has met the trigger conditions in Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, will be assigned a unique net margin value calculated as follows:

1. The Settlement Point Price at the Resource Node for Resource D (as determined for each SCED irresolvable constraint in Section 3.6.2, Methodology for Setting the Constraint Shadow Price Cap for a Constraint that is Irresolvable by SCED) is designated to be an irresolvable constraint net margin reference Settlement Point Price. This Settlement Point Price is unique to each SCED irresolvable constraint.
2. For these, ERCOT will calculate a constraint net margin in $/MW equal to the running sum of ¼ times the Maximum of either zero or that constraint’s (net margin reference Settlement Point Price – the POC) for all Real-Time Settlement Intervals in the current calendar year during which the constraint is binding (i.e. the constraint net margin calculation starts with the first operating day in the current calendar year during which the constraint meets the trigger conditions described in Section 3.6.1).
3. The Proxy Operating Cost (POC) in $/MWh used in step 2 for each of these constraints equals 10 times the Fuel Index Price (FIP) as defined in Section 2, Definitions and Acronyms, for the Business Day previous to the current Operating Day.
4. All constraint net margin values for these constraints that will be carried to the next calendar year will be reset to zero at the start of the next calendar year and a new running sum will be calculated daily.

**3.7 Methodology for Setting Transmission Shadow Price Caps for an IROL in SCED**

Upon implementation of an Interconnection Reliability Operating Limit (IROL), the shadow price cap of an IROL shall be set by ERCOT to A, below. If ERCOT, in its sole discretion, determines that A, below, is insufficient for SCED to manage an IROL, ERCOT shall use B, below, to determine the shadow price cap:

1. The value of the Generic Transmission Shadow Price Cap for Base Case constraints, as set in subsection 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, above; or
2. The maximum price value on the Power Balance Penalty Curve minus the mitigated offer floor for Resource H, as determined below, divided by Resource H’s Shift Factor impact to the constraint.

ERCOT shall include the shadow price cap for each IROL in the associated Generic Transmission Constraint (GTC) Methodology posted pursuant to Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

To determine Resource H, ERCOT shall identify all Generation Resources and Energy Storage Resource (ESRs) with positive Shift Factors not lower than 10% relative to the IROL and calculate the difference between the Seasonal net max sustainable rating (“seasonal High Sustained Limit (HSL)”) and the Seasonal net min sustainable rating (“seasonal Low Sustained Limit (LSL)”) for each Resource in effect at the time of the calculation. Starting with the Generation Resource or ESR with the highest positive Shift Factor, ERCOT will sum the differences between seasonal HSL and seasonal LSL until the sum is greater than or equal to the MW value that, if divided by 0.1 Hz, would equal the ERCOT System frequency bias (“bias MW value”). Resource H shall be the Generation Resource or ESR that results in this sum being greater than or equal to the bias MW value. If the sum of differences between the current seasonal HSL and seasonal LSL is not greater than or equal to the bias MW value, then Resource H will be the Generation Resource or ESR with the lowest positive shift factor not lower than 10%.

The shadow price cap and the Resource identified as Resource H for all applicable IROLs may be updated at any time based on ERCOT’s review and shall be reviewed by ERCOT at least annually. Any updates to IROL shadow price caps will be communicated through a Market Notice at least 30 days prior to becoming effective.

When the shadow price cap for an IROL is determined based on the process in B, above, then the process outlined in Section 3.6, Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED, does not apply to the IROL.

**4. Power Balance Shadow Price Cap**

**4.1 The Power Balance Penalty**

The Power Balance constraint is the balance between the ERCOT System Load and the amount of generation that is dispatched by SCED to meet that load. This Shadow Price for this constraint, also called System Lambda (λ), is the cost of providing one MWh of energy at the reference Electrical Bus. System Lambda, i.e. the Shadow Price for the Power Balance constraint, is equal to the change in the SCED objective function obtained by relaxing the Power Balance constraint by 1MW. The System Lambda is the energy component of LMP at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Curve proposed for PUCT approval.

The objective function for SCED is the sum of three components (1) the cost of dispatching generation (2) the penalty for violating Power Balance constraint (3) the penalty for violating network transmission constraints. SCED economically dispatches Generation Resources and Energy Storage Resources (ESRs) by minimizing this objective function within the generator physical limits and transmission limits. Since the Power Balance penalty is the maximum cost for meeting the Power Balance, SCED will re-dispatch generation to meet the Power Balance if the cost of re-dispatching the generation is less than cost of violating the Power Balance. When the cost of re-dispatching the Generation Resources and ESRs becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources and ESRs and the objective function is minimized with the Power Balance penalty determined by MW amount of the Power Balance constraint violation.

In the ERCOT design, SCED implements the Power Balance Penalty by a step function with up to 10 (Violation MW; Penalty $/MW) pairs. This curve determines the maximum System Lambda for a given amount of the Power Balance Constraint violation. The following section describes the factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MWh of violation and provides the resulting Power Balance Penalty Curve.

|  |
| --- |
| ***[OBDRR020: Replace Section 4.1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  The Power Balance constraint is the balance between the ERCOT System Load and the amount of generation that is dispatched by SCED to meet that load. This Shadow Price for this constraint, also called System Lambda (λ), is the cost of providing one MWh of energy at the reference Electrical Bus. System Lambda, i.e. the Shadow Price for the Power Balance constraint, is equal to the change in the SCED objective function obtained by relaxing the Power Balance constraint by 1MW. The System Lambda is the energy component of LMP at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Price proposed for PUCT approval.  The objective function for SCED is the sum of four components: (1) the cost of dispatching generation; (2) the cost of procuring Ancillary Services; (3) the penalty for violating Power Balance constraint; and (4) the penalty for violating network transmission constraints. SCED economically dispatches Generation Resources and ESRs and procures Ancillary Services by minimizing this objective function within the Resource physical limits and transmission limits. Since the Power Balance penalty is the maximum cost for meeting the Power Balance, SCED will re-dispatch generation to meet the Power Balance if the cost of re-dispatching the generation is less than cost of violating the Power Balance. When the cost of re-dispatching the Generation Resources and ESRs becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources and ESRs and the objective function is minimized with the Power Balance penalty determined by MW amount of the Power Balance constraint violation.  In the ERCOT design, SCED implements the under-generation Power Balance Penalty Price as a single value equal to the effective Value of Lost Load (VOLL) plus the effective Real-Time System-Wide Offer Cap (RTSWCAP) plus $0.01/MWh. This value determines the maximum System Lambda for a given amount of the Power Balance Constraint violation within the optimization. The SCED over-generation Power Balance Penalty Price is -$250/MWh. |

**4.2 Factors Considered in the Development of the Power Balance Penalty Curve**

ERCOT considered a number of factors in the development of the Power Balance Penalty Curve as described below. The dominant factor in the ERCOT qualitative analysis relates to the use of Regulation Ancillary Service capacity in place of generation capacity provided by the market to resolve the SCED Power Balance constraint violation. ERCOT submits that the Power Balance Penalty Curve presented herein represents a reasonable balance between the loss of the Regulation Ancillary Service capacity used to achieve system power balance and the market value of the energy deployed from the Generation Resources and Energy Storage Resources (ESRs) providing Regulation Ancillary Service.

The factors considered by ERCOT in its qualitative analysis, include the following:

* The amount of regulation that can be sacrificed without affecting reliability,
* The PUCT defined SWCAP,
* The expected percentage of intervals with SCED Up Ramp scarcity,
* The expected extent of Ancillary Service deployment by operators during intervals with capacity scarcity, and
* The transmission constraint penalty values.

The following discussion describes the details of these factors as they affect the Power Balance Penalty amounts.

Power Balance mismatch occurs whenever SCED is unable to find a dispatch at a cost lower than the Power Balance constraint Penalty. A Power Balance mismatch can occur under two conditions. One condition occurs when the amount of generation that is dispatched up to each resource’s HDLs is insufficient to meet the system load. This is referred to as an under generation and the System Lambda will be set by the under generation penalty. The opposite occurs when the amount of generation that is dispatched down to each resource’s LDLs is greater than the system load. This is referred to as an over generation and the System Lambda will be set by the over generation penalty. Both of these scenarios are unacceptable because, if left uncorrected by regulation, they result in the operation of the ERCOT system below (under generation) or above (over generation) the system frequency set point (nominally 60 Hertz). In the case of under generation, Load Frequency Control (LFC) will dispatch additional Regulation Service to correct the condition and restore system frequency to its set point (nominally 60 Hertz). On the other hand, in the case of over generation, LFC will dispatch reduced amounts of Regulation Service to correct the conditions and restore system frequency to its set point (nominally 60 Hertz). In other words, the Power Balance Penalty Curve acts as if it were an energy offer curve for a virtual Generation Resource injecting the amount of the Power Balance mismatch into the ERCOT system.

Since the actions that cause Regulation Ancillary Service capacity to be deployed to meet the Power Balance constraint reduces the amount of regulation capacity that can be used to maintain control of system frequency, the decision of the pricing of the power balance mismatch represents the value of the trade-off between the reduction in system reliability due to the use of the Regulation Ancillary Service and the cost to the Load Serving Entities (LSEs). The ERCOT system is particularly vulnerable to an inability to maintain system frequency because of the limited interchange capability of ERCOT with the Western and Eastern interconnects and, therefore, the larger the power balance mismatch, the larger the penalty amount.

In ERCOT, the PUCT has determined a maximum offer cap that is representative of supply side pricing associated with the concept of the value of lost load. By P.U.C. Subst. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, this amount is the High System-Wide Cap and ERCOT selected this amount to serve as the maximum value for the Power Balance Penalty.

Additionally, the Power Balance constraint can also be violated during operational scenarios characterized by Generation Resource and ESR ramp scarcity. SCED calculates dispatch limits (a HDL and a LDL) for each resource that represent the amount of dispatch that can be achieved by a Generation Resource or ESR at the end of a 5-minute interval at the resource’s specified ramp rate given current system conditions and the physical ability of the resource. The ramp rates used in this calculation are referred to as the SCED Up Ramp Rate (“SURAMP”) and the SCED Down Ramp Rate (“SDRAMP”). A ramp scarcity condition can occur when, for example during morning and evening system ramp intervals, the available capacity for increasing/decreasing Base Points (the sum of HDL minus current generation/the sum of current generation – LDL) is less than the actual system demand based on the rate at which the system Load is increasing/decreasing. Since the HDL and LDL are calculated based on the physical ramp rate of the resources, they cannot be violated. The likelihood of violation of Power Balance during ramp scarcity increases with the reduction in the capacity available for SCED that in turn depends on the operational philosophies. If Ancillary Services are deployed to maintain enough capacity that can be ramped in each SCED interval then the likelihood of Power Balance violation will be less. On the other hand if Ancillary Services are only deployed to maintain frequency and maintain online capacity and not deployed to maintain enough ramp capacity then the likelihood of Power Balance violation will be more. Along with the violation of the Power Balance Constraint in the over and under generation discussed above, Regulation Ancillary Service will be co-opted in this scenario to compensate for the SCED available capacity shortfall due to these ramp limitations. This scenario is also included in the ERCOT analysis for pricing the Power Balance Penalty.

ERCOT also considered the fact that near scarcity, the Power Balance Constraint can become violated as the result of the network transmission constraints that are also binding/violated at the same time. In this scenario LMPs will depend on the interaction of the Power Balance Penalty with the network transmission constraint Shadow Price caps (refer to the Appendix description of the SCED Energy LMP calculation to view this relationship). Under such condition the relative values of the network transmission constraint penalty and power balance penalty will determine whether resources with positive Shift Factor on the violated constraints will be moved up to meet Power Balance causing the network transmission constraint to become violated or will be moved down to resolve the network transmission constraint violation with a concomitant Power Balance violation.

Additionally, Protocols limit both the Energy Offer Curves (“EOCs”) and the proxy EOC created in SCED to the SWCAP. SCED uses the EOC submitted by a Qualified Scheduling Entity (QSE) for its Generation Resources and ESRs subject to the following. A proxy EOC is created in the SCED process if the QSE submitted EOC does not extend from LSL to HSL (in this case SCED extends the submitted EOC as described in Section 6.5.7.3, Security Constrained Economic Dispatch). A proxy EOC is also created for Generation Resources and ESRs operating on an Output Schedule. In this case, the proxy EOC is designed to limit the dispatch of these resources from their Output Schedule amounts by pricing this dispatch at values equal to the System-Wide floor or cap. Since the Power Balance Penalty curve can be characterized as equivalent to a virtual EOC, the relative value of the Power Balance Penalty to the EOCs used by SCED will determine whether the energy will be deployed from the EOC or the Power Balance Penalty curve. If the Power Balance constraint is violated in step one of SCED, then the Power Balance Penalty will set the reference LMP and the submitted and proxy EOCs will then be mitigated at the max of that reference LMP or verifiable cost in the second step of SCED. Consequently, if the Power Balance Penalty Curve provides a gradual ramp to SWCAP then the prices will gradually ramp to the SWCAP instead experiencing a sudden jump to SWCAP.

|  |
| --- |
| ***[OBDRR020: Delete Section 4.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]*** |

**4.3 The ERCOT Power Balance Penalty Curve**

Based on the criteria described in Section 4.2, Factors Considered in the Development of the Power Balance Penalty Curve, above, the SCED under-generation Power Balance Penalty is shown in the table below. The SCED over-generation Power Balance Penalty curve will be set to System-Wide Offer Floor.

| ***MW Violation*** | ***Penalty Value ($/MWh)*** |
| --- | --- |
| **≤ 5** | 250 |
| **5 < to ≤ 10** | 300 |
| **10 < to ≤ 20** | 400 |
| **20 < to ≤ 30** | 500 |
| **30 < to ≤ 40** | 1,000 |
| **40 < to ≤ 50** | 2,250 |
| **50 < to ≤ 100** | 4,500 |
| **> 100** | HCAP plus 1 |

The SCED under-generation Power Balance Penalty curve will be capped at LCAP plus $1 per MWh whenever the SWCAP is set to the LCAP.

**SCED Over-generation Power Balance Penalty Curve**

|  |  |
| --- | --- |
| ***MW Violation*** | ***Penalty Value ($/MWh)*** |
| **< 100,000** | **-250** |

|  |
| --- |
| ***[OBDRR020: Delete Section 4.3 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]*** |

**Appendix 1:** **The SCED Optimization Objective Function and Constraints**

The SCED optimization objective function is as given by the following:

Minimize {Cost of dispatching generation

+ Penalty for violating Power Balance constraint

+ Penalty for violating transmission constraints}

which is:

Minimize {sum of (offer price \* MW dispatched)

+ sum (Penalty \* Power Balance violation MW amount)

+ sum (Penalty \* Transmission constraint violation MW amount)}

The objective is subject to the following constraints:

* Power Balance Constraint

sum (Base Point) + under gen slack – over gen slack = Generation To Be Dispatched

* Transmission Constraints

sum(Shift Factor \* Base Point) – violation slack ≤ limit

* Dispatch Limits

LDL ≤ Base Point ≤ HDL

Based on the SCED dispatch the LMP at each Electrical Bus is calculated as

Where

= System Lambda or Power Balance Penalty (if a Power Balance violation exists) at time interval “t”

= Shift Factor impact of the bus “bus” on constraint “c” at time interval “t”

 = Shadow Price of constraint “c” at time interval “t” (capped at Max Shadow Price for this constraint).

During scarcity if a transmission constraint is violated then transmission constraint and Power Balance constraint will interact with each other to determine whether to move up or move down a resource with positive Shift Factor to the violated constraints if there are no other resources available.

* 1. Cost of moving up the Resource = Shift Factor \* Transmission Constraint Penalty + Offer cost
  2. Cost of moving down the Resource = Power Balance Penalty

The Resource will be moved down for resolving constraints if (a) > (b).

If (a) < (b) then the Resource will be moved up for meeting Power Balance.

|  |
| --- |
| ***[OBDRR020: Delete Appendix 1 above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]*** |

**Appendix 2:** **Day-Ahead Market Optimization Control Parameters**

The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and generation physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Section 4, Day-Ahead Operations. The bid‑based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation bids. The Offer‑based costs include costs from the Startup Offer, Minimum-Energy Offer, and Energy Offer Curve of Resources that submitted a Three-Part Supply Offer, as well as the DAM Energy-Only Offers, Congestion Revenue Right (CRR) offers, and Ancillary Service Offers. The DAM optimization’s objective function includes components that represent the bid based revenues and offer based cost and, additionally, penalty cost values that are used to control certain non‑economic aspects of the optimization as described below. These penalty values represent costs of constraint violations and they serve two purposes: rank constraints as relative violation priorities and limit the costs of constraint limitations. Based on paragraph (4)(c)(i) of Section 4.5.1, DAM Clearing Process, the transmission constraint limits needs to be satisfied in DAM and hence the transmission constraint penalty values are set to very high values to ensure that the constraints are not violated in DAM.

|  |
| --- |
| ***[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and Resource physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Section 4, Day-Ahead Operations. The bid‑based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation bids. The Offer‑based costs include costs from the Startup Offer, Minimum-Energy Offer, and Energy Offer Curve of Resources that submitted a Three-Part Supply Offer, as well as the DAM Energy-Only Offers, Congestion Revenue Right (CRR) offers, and Ancillary Service Offers. The DAM optimization’s objective function includes components that represent the bid based revenues and offer based cost and, additionally, penalty cost values that are used to control certain non‑economic aspects of the optimization as described below. These penalty values represent costs of constraint violations and they serve two purposes: rank constraints as relative violation priorities and limit the costs of constraint limitations. The Protocols require transmission constraint limits to be satisfied in DAM and hence the transmission constraint penalty values are set to very high values to ensure that the constraints are not violated in DAM. The DAM optimization will also consider Ancillary Service Demand Curves for each Ancillary Service product. |

The penalty factors used in the Day-Ahead optimization’s objective function are configurable and can be set by an authorized ERCOT Operator. Table 2-1 lists the available optimization penalty cost parameters that are controllable by the ERCOT Operator. The values provided for each of these parameters have been determined by ERCOT based on the results of the DAM quality of solution analysis and various DAM stress tests performed by ERCOT and, following the TNMID, may only be changed with the concurrence of the responsible ERCOT Director.

|  |
| --- |
| ***[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  The penalty factors used in the DAM optimization’s objective function are configurable and can be set by an authorized ERCOT Operator. Table 1-1 lists the available optimization penalty cost parameters that are controllable by the ERCOT Operator. The values provided for each of these parameters may only be changed with the concurrence of the responsible ERCOT Director. |

**TABLE 2 - 1**

|  |  |
| --- | --- |
| Penalty Function & Shadow Price Cap Cost Parameters | |
| Constraint | Penalty ($/MWh) |
| Over and Under - Generation Penalty Factors |  |
| Over Generation | 5,000,000.00 |
| Under Generation | 5,000,000.00 |
| Ancillary Service Penalty Factors |  |
| Regulation Down | SWCAP |
| Regulation Up | SWCAP |
| Responsive Reserve | SWCAP minus 0.01 |
| Non-Spin Reserve | SWCAP minus 0.03 |
| Network Transmission Penalty Factors |  |
| Base case 1-10KV | 350,000.00 |
| Base case 10.1-20KV | 450,000.00 |
| Base case 20.1-30KV | 550,000.00 |
| Base case 30.1-50KV | 650,000.00 |
| Base case 50.1-100KV | 750,000.00 |
| Base case 100.1-120KV | 850,000.00 |
| Base case 120.1-150KV | 950,000.00 |
| Base case 150+KV | 1,050,000.00 |
| Contingency 1-10KV | 300,000.00 |
| Contingency  10.1-20KV | 400,000.00 |
| Contingency  20.1-30KV | 500,000.00 |
| Contingency  30.1-50KV | 600,000.00 |
| Contingency  50.1-100KV | 700,000.00 |
| Contingency  100.1-120KV | 800,000.00 |
| Contingency  120.1-150KV | 900,000.00 |
| Contingency  150+KV | 1,000,000.00 |
| Non-thermal (e.g. generic constraints) | 1,000,000.00 |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[OBDRR020: Replace the Table 2-1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  **TABLE 1 - 1**   |  |  | | --- | --- | | Penalty Function & Shadow Price Cap Cost Parameters | | | Constraint | Penalty ($/MWh) | | Over and Under - Generation Penalty Factors |  | | Over Generation | 5,000,000.00 | | Under Generation | 5,000,000.00 | | Network Transmission Penalty Factors |  | | Base case 1-10KV | 350,000.00 | | Base case 10.1-20KV | 450,000.00 | | Base case 20.1-30KV | 550,000.00 | | Base case 30.1-50KV | 650,000.00 | | Base case 50.1-100KV | 750,000.00 | | Base case 100.1-120KV | 850,000.00 | | Base case 120.1-150KV | 950,000.00 | | Base case 150+KV | 1,050,000.00 | | Contingency 1-10KV | 300,000.00 | | Contingency  10.1-20KV | 400,000.00 | | Contingency  20.1-30KV | 500,000.00 | | Contingency  30.1-50KV | 600,000.00 | | Contingency  50.1-100KV | 700,000.00 | | Contingency  100.1-120KV | 800,000.00 | | Contingency  120.1-150KV | 900,000.00 | | Contingency  150+KV | 1,000,000.00 | | Non-thermal (e.g. generic constraints) | 1,000,000.00 | |

**2.1 Over/Under – Generation Penalty Factors**

In the ERCOT DAM an over/under energy supply condition (referred to here as over/under generation conditions) in an Operating Hour within the Operating Day can occur as a result of a strike of energy only block offers or the inherent lumpiness of Generation Resource and Energy Storage (ESR) strikes. The values of the Over/Under Generation Penalty Factors are chosen to allow the DAM clearing engine to select offers that result in the least amount of the over/under generation over the entire Operating Day and additionally, to enforce this constraint at the highest rank order relative to all other constraints. Additionally, the values of the Over/Under Generation Penalty Factors used in the DAM are considerably higher than the Power Balance Penalty Factor used in the SCED since DAM is a unit commitment problem and for it to clear reasonable offers and bids, the value of these penalty factors need to be high enough to reflect the start up and minimum generation cost of the committed resources. SCED, on the other hand, is an economic dispatch problem and hence for it to dispatch reasonable offers, the Power Balance Penalty Factor need only be in the order of the energy offer cost.

**2.2 Ancillary Service Penalty Factors**

The Ancillary Service penalty factors serve two purposes. The procured amount of an Ancillary Service can be lower than the difference between the amount of the required Ancillary Service, as specified in the Ancillary Service Plan, and the amount of the self-arranged AS. The value of the Ancillary Service penalty factors are chosen to allow the selection of Ancillary Service offers that result in the least amount of deficit considering the maximum Ancillary Service penalty factors referenced in Appendix 2, Table 2-1 for each given Ancillary Service over the Operating Day and to assign a priority to the Ancillary Service constraints relative to the enforcement of the Power Balance and Network Transmission constraints. Additionally, the increasing penalty cost structure from Non-Spinning Reserve (Non-Spin) Ancillary Service to Regulation Ancillary Service prioritizes the DAM Ancillary Service procurement as first Regulation Services, then Responsive Reserve (RRS), and lastly Non-Spin. In other words multiple offers from the same resource will be considered in the rank order given. Notably however, the Ancillary Service penalty factors are not used to set the Market Clearing Price for Capacity (MCPC) for each Ancillary Service. Instead, the infeasible Ancillary Service requirement amounts are reduced to the feasible level and the DAM clearing is rerun so that the price of the last Ancillary Service awarded MW sets the MCPC for each Ancillary Service. The Ancillary Service penalty factors used in DAM are also used in the Supplemental Ancillary Services Market (SASM) engine.

|  |
| --- |
| ***[OBDRR020: Delete Section 2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]*** |

**2.3 Network Transmission Penalty Factors**

The DAM Clearing Engine includes the Network Security Monitor (NSM) application and Network Constrained Unit Commitment (NCUC) application. These applications execute in a loop beginning with a NSM execution followed by a NCUC execution until a secure commitment pattern that maximizes the objective function is achieved (i.e. NSM begins with an estimated initial unit commitment and uses, thereafter, the latest NCUC commitment). The value of the Network Transmission Penalty Factors for each specified voltage level are used in NCUC application to set the rank order for relaxing the base case constraints and the security constrained network transmission constraints by voltage level and to set the rank order for the enforcement of the Network Transmission Constraints relative to the Power Balance and Ancillary Service requirements. The increasing value of the Network Transmission Penalty Factors for increasing voltage levels assures that base case and security constraint violations are relaxed progressively in the NSM and NCUC applications in order of voltage level, from lowest to highest. This assures that the DAM solution will honor network transmission constraints in the rank order from the 345 kV to the 69 kV voltage level. Additionally, these penalty factors are chosen such that, in each voltage range, the base case violations have a slightly higher penalty factor than the security constrained penalty factors. This assigns a higher priority in the NSM and NCUC to a network transmission base case violation compared to a network transmission security constrained violation. In other words, within the same voltage level, the security constraints are relaxed before the base case constraints.

Finally, the Non-thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints.

|  |
| --- |
| ***[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  The DAM Clearing Engine includes the Network Security Monitor (NSM) application and Network Constrained Unit Commitment (NCUC) application. These applications execute in a loop beginning with a NSM execution followed by a NCUC execution until a secure commitment pattern that maximizes the objective function is achieved (i.e. NSM begins with an estimated initial unit commitment and uses, thereafter, the latest NCUC commitment). The value of the Network Transmission Penalty Factors for each specified voltage level are used in NCUC application to set the rank order for relaxing the base case constraints and the security constrained network transmission constraints by voltage level and to set the rank order for the enforcement of the Network Transmission Constraints relative to the Power Balance constraint. The increasing value of the Network Transmission Penalty Factors for increasing voltage levels assures that base case and security constraint violations are relaxed progressively in the NSM and NCUC applications in order of voltage level, from lowest to highest. This assures that the DAM solution will honor network transmission constraints in the rank order from the 345 kV to the 69 kV voltage level. Additionally, these penalty factors are chosen such that, in each voltage range, the base case violations have a slightly higher penalty factor than the security constrained penalty factors. This assigns a higher priority in the NSM and NCUC to a network transmission base case violation compared to a network transmission security constrained violation. In other words, within the same voltage level, the security constraints are relaxed before the base case constraints. Finally, the Non-thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints. |

The values of the Network Transmission Penalty Factors chosen to enforce the Network Transmission Constraints are considerably higher in DAM when compared to the SCED (Network Transmission Shadow Price Caps) since the DAM is a unit commitment problem and for it to clear reasonable offers and bids, the Network Transmission Penalty Factors need to represent the higher costs associated with a unit start up and generation at minimum energy. The SCED is an economic dispatch problem and hence for it to dispatch reasonable offers; the penalties need only be in the order of energy offer cost.

**ERCOT Nodal Protocols**

**Section 23**

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

**TBD**

**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). In addition to the application, ERCOT must receive an application fee in the amount of $500 via Electronic Funds Transfer (EFT) (wire or Automated Clearing House (ACH)). All payments should reference the applicant’s name and Data Universal Numbering System (DUNS) Number (DUNS #) in the remarks. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application 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:** | |  | |
| **Telephone:** |  | | |
| **Email Address:** | | |  |

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Name:** | |  | |
| **Telephone:** |  | | |
| **Email Address:** | | |  |

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

Individual  Partnership  Municipally Owned Utility

Electric Cooperative  Limited Liability Company  Corporation

Other:

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

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Name:** | |  | |
| **Telephone:** |  | | |
| **Email Address:** | | |  |

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Name:** | |  | |
| **Telephone:** |  | | |
| **Email Address:** | | |  |

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Name:** | |  | |
| **Telephone:** |  | | |
| **Email Address:** | | |  |

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Name:** | |  | |
| **Telephone:** |  | | |
| **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, Energy Storage Resources (ESRs), or Load Resources shall designate a QSE qualified to represent the Resources. Resource Entities with Settlement Only Generators (SOGs) shall designate any qualified QSE.

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

**PART III – SIGNATURE**

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

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

**Attachment A – QSE Acknowledgment**

**Acknowledgment by Designated QSE for**

**Scheduling and Settlement Responsibilities with ERCOT**

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

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

The requested effective date for such representation is:      [[5]](#footnote-5)\*\*

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: |  |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR995: Replace Section 23, Form I above with the following upon system implementation:]***  **RESOURCE ENTITY**  **APPLICATION FOR REGISTRATION**  This application is for approval as a Resource Entity by the Electric Reliability Council of Texas, Inc. (ERCOT) in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary. The completed, executed application will be accepted by ERCOT via email to [MPRegistration@ercot.com](mailto:MPRegistration@ercot.com) (.pdf version). In addition to the application, ERCOT must receive an application fee in the amount of $500 via Electronic Funds Transfer (EFT) (wire or Automated Clearing House (ACH)). All payments should reference the applicant’s name and Data Universal Numbering System (DUNS) Number (DUNS #) in the remarks. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.  This application 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:** | |  | | | **Telephone:** |  | | | | **Email Address:** | | |  |   **2. Backup AR.** *(Optional)* This person may sign any form for which an AR’s signature is required and will perform the functions of the AR in the event the AR is unavailable.   |  |  |  |  | | --- | --- | --- | --- | | **Name:** | |  | | | **Telephone:** |  | | | | **Email Address:** | | |  |   **3.** **Type of Legal Structure.** (Please indicate only one.)  Individual  Partnership  Municipally Owned Utility  Electric Cooperative  Limited Liability Company  Corporation  Other:  If Applicant is not an individual, provide the state in which the Applicant is organized,      , and the date of organization:      .  **4. User Security Administrator (USA).** As defined in Section 16.12, User Security Administrator and Digital Certificates, the USA is responsible for managing the Market Participant’s access to ERCOT’s computer systems through Digital Certificates.   |  |  |  |  | | --- | --- | --- | --- | | **Name:** | |  | | | **Telephone:** |  | | | | **Email Address:** | | |  |   **5. Backup USA.** *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.   |  |  |  |  | | --- | --- | --- | --- | | **Name:** | |  | | | **Telephone:** |  | | | | **Email Address:** | | |  |   **6. Cybersecurity.** This contact is responsible for communicating Cybersecurity Incidents.   |  |  |  |  | | --- | --- | --- | --- | | **Name:** | |  | | | **Telephone:** |  | | | | **Email Address:** | | |  |   **7. Compliance Contact.** This person is responsible for compliance related issues.   |  |  |  |  | | --- | --- | --- | --- | | **Name:** | |  | | | **Telephone:** |  | | | | **Email Address:** | | |  |   **8. Proposed commencement date for service:**      .  **PART II – ADDiTIONAL REQUIRED Information**  **1. Officers.** ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State as having binding authority for the Applicant. ERCOT will use this list of individuals to determine who can execute such documents as the Standard Form Market Participant Agreement (Section 22, Attachment A), Amendment to Standard Form Market Participant Agreement (Section 22, Attachment C), Digital Certificate Audit Attestation, etc. Alternatively, additional documentation (Articles of Incorporation, Board Resolutions, Delegation of Authority, Secretary’s Certificate, etc.) can be provided to prove binding authority for the Applicant.  **2. Affiliates and Other Registrations.** Provide the name, legal structure, and relationship of each of the Applicant’s affiliates, if applicable. See Section 2.1, Definitions, for the definition of “Affiliate.” Please also provide the name and type of any other ERCOT Market Participant registrations held by the Applicant. *(Attach additional pages if necessary.)*  **3. Qualified Scheduling Entity (QSE) Acknowledgment.** Provide all information requested in Attachment A and have the document executed by both parties. Resource Entities representing Generation Resources or Load Resources shall designate a QSE qualified to represent the Resources. Resource Entities with Settlement Only Generators (SOGs) or Settlement Only Energy Storage Systems (SOESSs) shall designate any qualified QSE.   |  |  |  | | --- | --- | --- | | **Affiliate Name**  (or name used for other ERCOT registration) | **Type of Legal Structure**  (partnership, limited liability company, corporation, etc.) | **Relationship**  (parent, subsidiary, partner, affiliate, etc.) | |  |  |  | |  |  |  | |  |  |  | |  |  |  | |  |  |  | |  |  |  | |  |  |  | |  |  |  | |  |  |  | |  |  |  |   **PART III – SIGNATURE**  I affirm that I have personal knowledge of the facts stated in this application and that I have the authority to submit this application form on behalf of the Applicant. I further affirm that all statements made and information provided in this application form are true, correct and complete, and that the Applicant will provide to ERCOT any changes in such information in a timely manner.   |  |  | | --- | --- | | Signature of AR, Backup AR or Officer: |  | | Printed Name of AR, Backup AR or Officer: |  | | Date: |  |   **Attachment A – QSE Acknowledgment**  **Acknowledgment by Designated QSE for**  **Scheduling and Settlement Responsibilities with ERCOT**  The Applicant below has named the QSE listed below as its designated QSE to represent the Applicant for scheduling and Settlement transactions with ERCOT.  The Applicant’s designated QSE, listed below, hereby acknowledges that it does represent the Applicant and that it shall be responsible for the Applicant’s scheduling and Settlement transactions with ERCOT pursuant to the ERCOT Protocols.  The requested effective date for such representation is:      [[6]](#footnote-6)\*\*  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. Pursuant to Protocol Section 3.14.1.1, Notification of Suspension of Operations, this date must be at least 150 days (or 90 days if the Resource will mothball and operate under a Seasonal Operation Period) from the date ERCOT receives this Notification. [↑](#footnote-ref-1)
2. ERCOT will remove the Resource(s) from its registration systems if this option is selected. [↑](#footnote-ref-2)
3. In accordance with Section 3.14.1.9, Generation Resource/Energy Storage Resource Status Updates, ERCOT will remove the Generation Resource(s) or ESR(s) from its registration upon Resource Entity updating Resource Registration accordingly. [↑](#footnote-ref-3)
4. A distributed load reference bus is assumed in this attachent, and all shift factor values refer to the flow on a constraint (either pre- or post-contingency) assuming an injection at the location in question

   and a withdrawal at the reference bus. [↑](#footnote-ref-4)
5. \*\* *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-5)
6. \*\* *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-6)