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| NPRR Number | [1290](https://www.ercot.com/mktrules/issues/NPRR1290) | NPRR Title | Gap Resolutions and Clarifications for the Implementation of RTC+B |
| Date of Decision | | August 27, 2025 | |
| Action | | Recommended Approval | |
| Timeline | | Normal | |
| Estimated Impacts | | Phase 1:  Cost/Budgetary: None  Project Duration: No project required  Phase 2:  Cost/Budgetary: Between $75K and $100K  Project Duration: 5 to 7 months | |
| Proposed Effective Date | | Phase 1: Upon system implementation of PR447, Real-Time Co-Optimization (RTC)  Phase 2: Upon system implementation | |
| Priority and Rank Assigned | | Phase 1: Not applicable  Phase 2: Priority – 2026; Rank – 4800 | |
| Nodal Protocol Sections Requiring Revision | | 2.1, Definitions  2.2, Acronyms and Abbreviations  3.1.6.9, Withdrawal of Approval and Rescheduling of Approved Planned Outages of Resource Facilities  3.17.2, Responsive Reserve Service  3.18, Resource Limits in Providing Ancillary Service  4.4.7.1, Self-Arranged Ancillary Service Quantities  4.4.9.3.1, Energy Offer Curve Criteria  4.4.9.5.1, DAM Energy-Only Offer Curve Criteria  4.4.9.6.1, DAM Energy Bid Criteria  4.4.9.7.1, Energy Bid/Offer Curve Criteria  4.4.9.8, Energy Bid Curves  4.4.9.8.1, Energy Bid Curve Criteria  6.3, Adjustment Period and Real-Time Operations Timeline  6.5.5.2, Operational Data Requirements  6.5.7.3, Security Constrained Economic Dispatch  6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder  6.5.7.5, Ancillary Service Capacity Monitor  6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node  6.6.9, Emergency Operations Settlement  6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT  6.7.5.5, Non-Spinning Reserve Service Payments and Charges  6.7.5.6, ERCOT Contingency Reserve Service Payments and Charges  7.9.1.3, Minimum and Maximum Resource Prices  8.1.1.2.1.2 Responsive Reserve Qualification  16.11.4.1, Determination of Total Potential Exposure for a Counter-Party  22, Attachment P, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints | |
| Related Documents Requiring Revision/Related Revision Requests | | None | |
| Revision Description | | This Nodal Protocol Revision Request (NPPR) addresses several gaps and provides necessary clarifications in the Protocol language to support implementation of the Real-Time Co-optimization plus Batteries (RTC+B) initiative.  The proposed changes are summarized below and listed in the order in which applicable language first appears in the NPRR:   1. When discussing Energy Offer Curves and Energy Bid/Offer Curves in the Protocols, there is language referring to them as both “monotonically non-decreasing” and “monotonically increasing.” The true requirement is that the curves must be “monotonically non-decreasing,” recognizing that “monotonically increasing” curves meet this requirement. As such, all references are updated to consistently use the “monotonically non-decreasing” terminology. Equivalent changes are made for Energy Bids where both “monotonically non-increasing” and “monotonically decreasing” terminology is used.   With these changes, ERCOT also proposes a requirement that submitted curves do not have “more than two consecutive price/quantity pairs at the same price or quantity.” This requirement does not affect the ability of a Qualified Scheduling Entity (QSE) to shape their submitted curves but does address an issue observed by ERCOT staff for the Day-Ahead Market (DAM).   1. There are multiple proposed language changes and clarifications regarding the “frequency responsive” capability telemetry provided to ERCOT by QSEs. Of particular note, ERCOT is proposing to retain the existing Non-Frequency Responsive Capacity (NFRC) telemetry currently provided by QSEs. While it was initially expected that this telemetry would be removed with RTC+B, ERCOT has identified instances in which that information is still useful and necessary. 2. Under Section 3.1.6.9, following receipt of an Outage Schedule Adjustment (OSA) for a Resource, a “QSE must update the Resource’s Energy Offer Curve to $4,500/MWh for all MW level…” Under RTC+B, with the Real-Time System-Wide Offer Cap (RTSWCAP) at $2,000/MWh, a QSE will not be able to comply with this requirement. As such, ERCOT is proposing to change the “$4,500/MWh” requirement to RTSWCAP until NPRR930 can be implemented, after which the OSA Energy Curve Offer process will be automated within ERCOT’s systems and the submission validation rules for a QSE will not apply. 3. In reviewing Section 4.4.7.1, ERCOT has identified that the language unnecessarily limits Ancillary Service trade activity and goes beyond the intent of addressing concerns with the management of Ancillary Service self-provision and Ancillary Service sub-type limits. Language is proposed to loosen those restrictions and focus exclusively on Ancillary Service sub-types that can be self-provided. 4. Several clarifications are made regarding emergency operations Settlement. This includes language to refer to conditions in which Base Points are inconsistent with Real-Time Locational Marginal Prices (LMPs), as opposed to Settlement Point Prices. This is appropriate as SPPs have 15-minute granularity in Real-Time, whereas both Base Points and LMPs have Security-Constrained Economic Dispatch-level (SCED-level) granularity. Additionally, changes have been made to the references to Ancillary Service Offers to clarify that this is an offer and not a curve, state that the Settlement will use the submitted offers in the calculation, and explain what price will be used if the Ancillary Service Offer submitted is a partial offer. 5. Within Section 6.5.5.2, there is language describing how State of Charge (SOC) data will be used in calculating a Resource’s High Ancillary Service Limit (HASL). As the concept of a HASL no longer exists with RTC+B, ERCOT is proposing that the applicable language be struck with RTC+B implementation. 6. Under the Protocol language for RTC+B, “[t]he System Lambda used to determine LMPs from SCED Step 2 shall be capped at the effective [Value of Lost Load] (VOLL).” In discussions with ERCOT stakeholders, it has been identified that a Resource’s QSE may face significant financial harm under a limited number of circumstances under which the capping process is applied. As a near-term solution to mitigate this risk, ERCOT is proposing to compensate QSEs whose Resources meet a defined set of criteria, further laid out in the proposed language below, when the capping process is triggered. The proposal is to make use of existing emergency operations Settlement logic, similar to what is used in the case of a Real-Time Market price correction or dispatch limit “manual override.” The formulas used for determining any compensation would be based on what already exists in Section 6.6.9.1, Payment for Emergency Operations Settlement. As a longer-term solution, this NPRR also proposes a “Phase 2” where any LMP above VOLL is set equal to the greater of VOLL or the difference between the LMP minus the positive difference between System Lambda and VOLL. All other LMPs below VOLL remain unchanged. Phase 2 also eliminates the significant financial harm described above thereby eliminating the need to compensate QSEs due to System Lambda capping. 7. For the SCED pricing run process described in Section 6.5.7.3.1, the current language for RTC+B has inconsistencies and errors when describing the Resources for which the dispatch limits should be relaxed. This NPRR excludes all Resources with a telemetered Resource Status of either ONTEST, ONHOLD, or ONSC, as these Resources are effectively unable to be dispatched by SCED to a level other than their current operating level. 8. In the current RTC+B language under Section 6.5.7.3.1, for a Controllable Load Resource (CLR), the Low Dispatch Limit (LDL) is calculated using Normal ramp rate down and the High Dispatch Limit (HDL) is calculated using Normal ramp rate up.  However, under Section 6.5.7.2, for the calculations in the Resource Limit Calculator (RLC) for a CLR, the LDL is calculated using Normal ramp rate up and HDL is calculated using Normal ramp rate down. Language changes are being proposed to Section 6.5.7.3.1 to make the two sections consistent. 9. For the Generation Resource Supervisory Control and Data Acquisition (SCADA) Splitting Percentage formula defined in Section 6.6.3.1, the calculations are updated to only use “the sum of all positive SCADA values for all Resources that are included in the net metering configuration.” As the calculations also apply to Energy Storage Resources (ESRs), this change is necessary to accommodate the transition to a “single-model” for ESRs. 10. ERCOT staff has identified uses of the term “System-Wide Offer Cap (SWCAP)” which were either missed during the development of RTC+B Protocol language or added after the current RTC+B Protocol was approved. Because that term is being replaced after RTC+B implementation with separate SWCAPs for DAM and the Real-Time Market (RTM), SWCAP is replaced with the correct term throughout. 11. Proposed language changes to clarify the default Responsive Reserve Service Primary Frequency Response (RRS-PFR) amount for a newly qualified Generation Resource, ESR or CLR in Section 3.18 and Section 8.1.1.2.1.2 by defining Maximum Droop Response Range (MDRR) based on their droop characteristics. Also, under Section 6.5.7.5, the PRC8 and PRC9 calculations have been corrected to reflect the ESR single model. 12. Corrected the spelling of the acronyms for the market clearing price for Non-Spinning Reserve Service (Non-Spin) and ERCOT Contingency Reserve Service (ECRS) in the Settlement equations in paragraph (3) of both Sections 6.7.5.5 and 6.7.5.6. | |
| 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 | | The gaps addressed and clarification provided by this NPRR to the Protocol language are needed for implementation of RTC+B project to avoid the potential for confusion and to mitigate risk for ERCOT and QSEs representing Resources at launch.  This NPRR is focused on solutions and clarifications that can be incorporated into the RTC+B project without creating implementation risk. While it may be desirable in some cases to pursue alternative proposals in the longer-term, ERCOT respectfully request that those alternative proposals be considered as distinct NPRRs. | |
| PRS Decision | | On 7/16/25, PRS voted unanimously to recommend approval of NPRR1290 as amended by the 7/2/25 HEN comments. All Market Segments participated in the vote.  On 8/13/25, PRS voted unanimously to endorse and forward to TAC the 7/16/25 PRS Report as revised by PRS and 8/12/25 Revised Impact Analysis for NPRR1290 with a recommended priority of 2026 and rank of 4800 for Phase 2. All Market Segments participated in the vote. | |
| Summary of PRS Discussion | | On 7/16/25, ERCOT Staff provided an overview of NPRR1290 and expressed support for the phased approach proposed within the 7/2/25 HEN comments.  On 8/13/25, PRS reviewed the 8/12/25 Revised Impact Analysis for NPRR1290 and discussed the appropriate priority and rank for Phase 2. ERCOT Staff presented a desktop edit to clarify the proposed posting requirements within paragraph (15)(d) of Section 6.5.7.3. | |
| **TAC Decision** | | On 8/27/25, TAC voted unanimously to recommend approval of NPRR1290 as recommended by PRS in the 8/13/25 PRS Report. All Market Segments participated in the vote. | |
| **Summary of TAC Discussion** | | On 8/27/25, 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) | |

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| **Opinions** | |
| **Credit Review** | ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1290 and notes it updates usage of SWCAP to DACWAP but 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 NPRR1290. |
| **ERCOT Opinion** | ERCOT supports approval of NPRR1290. |
| **ERCOT Market Impact Statement** | ERCOT Staff has reviewed NPRR1290 and believes the market impact for NPRR1290 provides clarification and addresses gaps ahead of the implementation of RTC+B. |

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| Market Segment | Not applicable |

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| **Comments Received** | |
| **Comment Author** | **Comment Summary** |
| HEN 061625 | Proposed an alternative approach to addressing Locational Marginal Prices (LMPs) when System Lambda is capped |
| ERCOT 062425 | Provided additional clarifying revisions and responded to the HEN proposal |
| HEN 070225 | Proposed revisions to carry over the concepts from the 6/16/25 HEN comments onto the 6/24/25 ERCOT comments as a “Phase 2” for implementation after RTC go-live |
| Joint Commenters 070725 | Expressed support for the 7/2/25 HEN comments |
| WMS 070925 | Endorsed NPRR1290 as amended by the 7/2/25 HEN comments |

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| Market Rules Notes |

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

* NPRR1238, Registration of Loads with Curtailable Load Capabilities (incorporated 8/1/25)
  + Section 6.5.7.3.1
* NPRR1268, RTC – Modification of Ancillary Service Demand Curves (incorporated 6/1/25)
  + Section 6.5.7.3
* NPRR1269, RTC+B Three Parameters Policy Issues (incorporated 6/1/25)
  + Section 6.5.7.3
* NPRR1270, Additional Revisions Required for Implementation of RTC (incorporated 6/1/25)
  + Section 6.5.5.2

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

* NPRR1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
  + Section 6.5.7.3.1
* NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  + Section 4.4.7.1
  + Section 6.5.5.2
  + Section 6.5.7.3.1

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| Proposed Protocol Language Revision |

**2.1 DEFINITIONS**

**Day-Ahead Market (DAM) Energy Bid**

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

**Energy Offer Curve**

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

**Low System-Wide Offer Cap (LCAP) Effective Period**

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

**Non-Frequency Responsive Capacity (NFRC)**

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



***Regulation Up Service (Reg-Up)***

An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available above any Base Point but below the High Sustained Limit (HSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Up must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Up above the Load Resource’s Low Power Consumption (LPC) limit.

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| ***[NPRR1013 and NPRR1014: Replace applicable portions of the definition “Regulation Up Service (Reg-Up)” above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively:]***  ***Regulation Up Service (Reg-Up)***  An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available above any Base Point but below the high limit in MW of the Generation Resource’s capacity that is frequency responsive and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. An Energy Storage Resource (ESR) providing Reg-Up must be able to modify its energy withdrawal or injection as deployed for Reg-Up across the full range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Up must be able to increase and decrease Load as deployed within its Ancillary Service award for Reg-Up above the Load Resource’s Low Power Consumption (LPC) limit. |

***Regulation Down Service (Reg-Down)***

An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available below any Base Point but above the Low Sustained Limit (LSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Down must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource’s Maximum Power Consumption (MPC) limit.

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| ***[NPRR1013 and NPRR1014: Replace applicable portions of the definition “Regulation Down Service (Reg-Down)” above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project; or upon system implementation of NPRR1014, respectively:]***  ***Regulation Down Service (Reg-Down)***  An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available below any Base Point but above the low limit in MW of the Generation Resource’s capacity that is frequency responsive and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. An Energy Storage Resource (ESR) providing Reg-Down must be able to modify its energy withdrawal or injection as deployed for Reg-Down across the full range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Down must be able to increase and decrease Load as deployed within its Ancillary Service award for Reg-Down below the Load Resource’s Maximum Power Consumption (MPC) limit. |

**Maximum Droop Response Range (MDRR)**

This value reflects the total capability of a Resource to respond to system frequency deviations based on its droop characteristics. The MDRR for a Generation Resource is its High Sustained Limit (HSL), for a Controllable Load Resource is its Maximum Power Consumption (MPC), and for an Energy Storage Resource (ESR) is the difference between its HSL and Low Sustained Limit (LSL). This capability will be used to determine the maximum Responsive Reserve Service (RRS) using Primary Frequency Response (PFR) that a Resource can be awarded in DAM or Real-Time.

**2.2** **ACRONYMS AND ABBREVIATIONS**

**MDRR**  Maximum Droop Response Range

**NFRC** Non-Frequency Responsive Capacity



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

(1) If ERCOT believes it cannot meet applicable reliability standards and has exercised all other reasonable options, and any actions taken pursuant to Section 3.1.4.6, Outage Coordination of Potential Transmission Emergency Conditions, have not resolved the situation, then ERCOT shall conduct a preliminary Outage Adjustment Evaluation (OAE) and issue an Advance Action Notice (AAN) pursuant to Section 6.5.9.3.1.1, Advance Action Notice.

(a) The AAN shall describe the reliability problem, the date and time that the possible Emergency Condition would begin, the date and time that the possible Emergency Condition would end, and a summary of the actions ERCOT believes it might take, including, if applicable, the amount of capacity it would seek from one or more OSAs based on the preliminary OAE. The AAN must state the earliest time at which ERCOT will issue OSAs, if an OSA is deemed necessary.

(b) ERCOT shall issue the AAN a minimum of 24 hours prior to issuing any OSA. Additionally, unless impracticable pursuant to paragraph (3)(f) below, OSAs should not be issued until eight Business Hours have elapsed following issuance of the AAN. ERCOT shall not issue an OSA under this Section unless it has first completed an updated OAE after these time periods have passed.

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

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

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

(2) Before the time stated in the AAN when ERCOT will issue any OSAs, each QSE shall:

(a) Update its Resource COPs and the Outage Scheduler to the best of its ability to reflect any decisions to voluntarily delay or cancel any Outage so as to remove the Outage from updated OAE and OSA consideration;

(b) Notify ERCOT if a specific Resource cannot be considered for an OSA, for all or part of the period covered by the AAN, due to Resource reliability, compliance with contractual warranty obligations, or other reasons beyond the Resource’s control; and

(c) Notify ERCOT of any Resource that is currently on Outage that the QSE agrees could be returned to service, upon receipt of an OSA, for all or part of the period covered by the AAN.

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

(a) ERCOT may contact QSEs representing Resources for more information prior to conducting any updated OAE or issuing an OSA.

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

(c) ERCOT will not consider any Resource for an OSA if the Resource’s QSE notified ERCOT prior to the earliest issuance time of any OSA stated in the AAN that the Resource cannot be considered for an OSA for the reasons specified in paragraph (2)(b) above.

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

(e) After the earliest issuance time of the OSAs stated in the AAN, if the updated OAE shows that one or more OSAs is still necessary, ERCOT shall post a message to the ERCOT website stating that it will issue one or more OSAs and shall provide verbal notice to TSPs and QSEs via the Hotline. Subsequent to this notification, and for the entire period identified in the AAN, the QSE may not voluntarily modify the Resource’s Outage, but is subject to the issuance of an OSA.

(f) ERCOT may only issue an OSA to the QSE for a Resource that has a Resource Outage in the Outage Scheduler during the timeframe of the forecasted Emergency Condition described above in this section.

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

(h) Following the receipt of an OSA, for the OSA Period:

(i) The QSE for the Resource may choose to show the Resource as OFF in the COP or may elect to leave the Resource On-Line due to equipment or reliability concerns or if the Resource Category is coal or lignite. If the QSE for the Resource intends to leave the Resource On-Line, it must communicate to the ERCOT control room the anticipated start and end time of the On-Line period. ERCOT will issue one or multiple RUC instructions to the QSE of the Resource for the anticipated On-Line period within the OSA Period for each Operating Day. While On-Line, the Resource must utilize a status of ONRUC and cannot opt out of RUC Settlement;

(ii) If the Resource remains On-Line pursuant to paragraph (i) above, it must remain at Low Sustained Limit (LSL) unless deployed above LSL by Security-Constrained Economic Dispatch (SCED);

(iii) If the Resource has a COP Resource Status of OFF at any point during the OSA Period, and ERCOT requires the Resource to be On-Line, or if ERCOT requires a Resource with a planned derate to maintain its capacity, ERCOT will issue a RUC instruction to the Resource’s QSE for the required commitment period. While On-Line, the Resource must utilize a status of ONRUC and cannot opt out of RUC Settlement;

(iv) The QSE must update the Resource’s Energy Offer Curve to be equal to the Real-Time System-Wide Offer Cap (RTSWCAP) for all MW levels from 0 MW to the HSL; and

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| ***[NPRR930: Replace paragraph (iv) above with the following upon system implementation:]***  (iv) ERCOT shall create proxy Energy Offer Curves for the Resource under paragraph (4)(d)(iii) of Section 6.5.7.3, Security Constrained Economic Dispatch; and |

(v) The QSE for the Resource cannot submit a Three Part Supply Offer into the Day-Ahead Market (DAM) for any Operating Day during the OSA Period.

(4) ERCOT shall work in good faith with the QSEs to reschedule any delayed or canceled Outages resulting from an AAN under paragraph (1) above, regardless of whether the Resource took voluntary actions or received an OSA. The Outage must be rescheduled so that it is completed within 120 days of the end of the OSA Period. ERCOT, in its sole discretion, may approve any Outage that is rescheduled due to an AAN or OSA even if it would cause the aggregate MW of approved Resource Outages to exceed the Maximum Daily Resource Planned Outage Capacity.

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

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

(5) If insufficient capacity to meet the need described in the AAN is made available through the processes described in paragraphs (2) and (3) above, ERCOT may contact QSEs with Resources that are currently on Outage in the Outage Scheduler and that the QSE has agreed could be returned to service upon receipt of an OSA. ERCOT may issue an OSA to the QSE for any Resource that the QSE agrees can feasibly be returned to service during the period of the possible Emergency Condition described in the AAN.

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

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

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

(k) SODG and SOTG forecasts;

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

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

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

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| ***[NPRR995: Replace paragraph (7) above with the following upon system implementation:]***  (7) The preliminary OAE may not assume total renewable production lower than the sum of the selected Wind-powered Generation Resource Production Potential (WGRPP) and PhotoVoltaic Generation Resource Production Potential (PVGRPP) forecasts for each hour less any reasonably expected severe weather impacts. The available capacity in ERCOT’s preliminary OAE must include targeted reserve levels and include forecasted capacity available through DC Tie imports or curtailment of DC Tie exports, forecasted capacity provided from Settlement Only Distributed Generators (SODGs), Settlement Only Transmission Generators (SOTGs), Settlement Only Distribution Energy Storage Systems (SODESSs), and Settlement Only Transmission Energy Storage Systems (SOTESSs), and forecasted capacity from price-responsive Demand based on information reported to ERCOT in accordance with Section 3.10.7.2.1, Reporting of Demand Response. ERCOT must post the following inputs to the preliminary OAE to the ERCOT website within an hour of issuing an AAN, including but not limited to:  (a) The Load forecast;  (b) Load forecast vendor selection;  (c) Wind forecast;  (d) Wind forecast vendor selection;  (e) Solar forecast;  (f) Solar forecast vendor selection;  (g) Expected severe weather impacts forecast;  (h) Targeted reserve levels;  (i) DC Tie import forecast;  (j) DC Tie export curtailment forecast;  (k) SODG, SOTG, SODESS, and SOTESS forecasts;  (l) The forecast of capacity provided by price-responsive Demand;  (m) Any aggregate derating of Resource(s) and/or Forced Outage assumptions in total MWs; and  (n) Any aggregate fuel derating assumptions in total MWs. |

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

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

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

***3.17.2*** ***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 its Frequency Responsive Capacity (FRC);(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) Controllable Load Resources (CLRs); and

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

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| ***[NPRR1246: Insert item (f) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (f) ESRs. |

**3.18 Resource Limits in Providing Ancillary Service**

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

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| ***[NPRR1007 and NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (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 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.

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| ***[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 using Primary Frequency Response awarded to or self-arranged from an On-Line Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in Nodal Operating Guide Section 8, Attachment N, Procedure for Calculating RRS MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response, a maximum MW amount of RRS using Primary Frequency Response for each Resource subject to verified droop performance. The default value for any newly qualified Resource not yet evaluated per Nodal Operating Guide Section 8, Attachment N 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.

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| ***[NPRR1007 and NPRR1246: 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 using Primary Frequency Response that can be provided by an On-Line Resource is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in Nodal Operating Guide Section 8, Attachment N, Procedure for Calculating RRS MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response, a maximum MW amount of RRS using Primary Frequency Response for each Resource subject to verified droop performance. The default value for any newly qualified Resource not yet evaluated per Nodal Operating Guide Section 8, Attachment N shall be 20% of its Maximum Droop Response Range (MDRR). 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 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.

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| ***[NPRR1007 and NPRR1246: 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 or ESR 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. |

***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.

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| ***[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. |

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| ***[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.

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| ***[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.

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

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

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| ***[NPRR1008: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (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.

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| ***[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) For Ancillary Services sub-types that can be self-provided, a QSE shall not submit Ancillary Services trades that result in the QSE’s net purchased quantities of Ancillary Services exceeding the sum of the QSE’s Self-Arranged Ancillary Service Quantities and DAM Ancillary Service Awards.  (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 the sum of their Self-Arranged Ancillary Service Quantities and DAM Ancillary Service Awards 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.

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| ***[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. |

***4.4.9.3.1 Energy Offer Curve Criteria***

(1) Each Energy Offer Curve must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) A monotonically non-decreasing offer curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs and no more than two consecutive price/quantity pairs at the same price or quantity;

(d) The first and last hour of the Offer;

(e) The expiration time and date of the offer;

(f) List of Ancillary Service Offers from the same Resource;

(g) Inclusive or exclusive designation relative to other DAM offers;

(h) Percentage of FIP and percentage of FOP for generation above LSL subject to the sum of the percentages not exceeding 100%; and

(i) Reason for update of the offer, if submitting after the end of the Adjustment Period.

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| ***[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (1) Each Energy Offer Curve must be reported by a QSE and must include the following information:  (a) The selling QSE;  (b) The Resource represented by the QSE from which the offer would be supplied;  (c) A monotonically non-decreasing offer curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs and no more than two consecutive price/quantity pairs at the same price or quantity;  (d) The first and last hour of the Offer;  (e) The expiration time and date of the offer;  (f) Inclusive or exclusive designation relative to other DAM offers (for Real-Time, Energy Offer Curves are always considered to be inclusive with Ancillary Service Offers);  (g) Percentage of FIP and percentage of FOP for generation above LSL subject to the sum of the percentages not exceeding 100%; and  (h) Reason for update of the offer, if submitting after the end of the Adjustment Period. |

(2) An Energy Offer Curve must be within the range of -$250.00 per MWh and the SWCAP in dollars per MWh. The software systems must be able to provide ERCOT with the ability to enter Resource-specific Energy Offer Curve floors and caps.

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| ***[NPRR1008 and NPRR1245: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) An Energy Offer Curve must be within the range of -$250.00 per MWh and either the DASWCAP or RTSWCAP, depending on the timing of the submission, in dollars per MWh. No Energy Offer Curve received after 1430 in the Day-Ahead may contain a price exceeding the RTSWCAP.  After 1430 in the Day-Ahead, ERCOT shall cancel any Energy Offer Curve containing a price exceeding the RTSWCAP and notify the QSE of the expiration via an electronic message. |

(3) The minimum amount per Resource for each Energy Offer Curve that may be offered is one MW.

***4.4.9.5.1 DAM Energy-Only Offer Curve Criteria***

(1) Each DAM Energy-Only Offer Curve must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Settlement Point;

(c) The fixed quantity block, variable quantity block, or curve indicator for the offer;

(i) If a fixed quantity block, the single price (in $/MWh) and single quantity (in MW) for all hours offered in that block , which may clear at a Settlement Point Price less than the offer price for that block;

(ii) If a variable quantity block, the single price (in $/MWh) and single “up to” quantity (in MW) contingent on the purchase of all hours offered in that block; and

(iii) If a curve, a monotonically non-decreasing energy offer curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs and no more than two consecutive price/quantity pairs at the same price or quantity;

(d) The first and last hour of the offer; and

(e) The expiration time and date of the offer.

(2) A DAM Energy-Only Offer Curve must be within the range of -$250.00 per MWh and the SWCAP in dollars per MWh.

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| ***[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  (2) A DAM Energy-Only Offer Curve must be within the range of -$250.00 per MWh and the DASWCAP in dollars per MWh. |

(3) The minimum amount for each DAM Energy-Only Offer Curve that may be offered is one MW.

(4) DAM Energy-Only Offers, DAM Energy Bids, and/or PTP Obligation bids shall not be submitted in combination to create the net effect of a single PTP Obligation containing a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points for the QSE or for any combination of QSEs within the same Counter-Party.

***4.4.9.6.1 DAM Energy Bid Criteria***

(1) Each DAM Energy Bid must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The Settlement Point;

(c) Fixed quantity block, variable quantity block, or curve indicator for the bid;

(i) If a fixed quantity block, the single price (in $/MWh) and single quantity (in MW) for all hours bid in that block, which may clear at a Settlement Point Price greater than the bid price for that block;

(ii) If a variable quantity block, the single price (in $/MWh) and single “up to” quantity (in MW) contingent on the purchase of all hours bid in that block; and

(iii) If a curve, a monotonically non-increasing energy bid curve for price (in $/MWh) and monotonically increasing for quantity (in MW) with no more than 10 price/quantity pairs and no more than two consecutive price/quantity pairs at the same price or quantity.

(d) The first and last hour of the bid; and

(e) The expiration time and date of the bid.

(2) The minimum amount for each DAM Energy Bid that may be bid is one MW.

(3) DAM Energy-Only Offers, DAM Energy Bids, and/or PTP Obligation bids shall not be submitted in combination to create the net effect of a single PTP Obligation containing a source Settlement Point and a sink Settlement Point that are Electrically Similar Settlement Points for the QSE or for any combination of QSEs within the same Counter-Party.

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| ***[NPRR1014: Insert Section 4.4.9.7.1 below upon system implementation:]***  ***4.4.9.7.1 Energy Bid/Offer Curve Criteria***  (1) Each Energy Bid/Offer Curve must be reported by a QSE representing an ESR and must include the following information:  (a) The selling QSE;  (b) The ESR represented by the QSE from which the bid and offer would be provided;  (c) A monotonically non-decreasing curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs and no more than two consecutive price/quantity pairs at the same price or quantity. Negative MW values cover the charging MW range, and the positive MW values cover the discharging MW range. The price points corresponding to the charging MW range represent the not-to-exceed bid prices to consume energy, and the price points corresponding to the discharging MW range represent the offer prices to sell energy;  (d) The first and last hour of the offer;  (e) The expiration time and date of the offer;  (2) An Energy Bid/Offer Curve shall be bounded by -$250.00 per MWh and either the DASWCAP or RTSWCAP depending on the timing of the submission in dollars per MWh. The ERCOT systems must allow ERCOT to enter ESR-specific Energy Bid/Offer Curve floors and caps.  (3) In DAM and RTM, an Energy Bid/Offer Curve shall be considered to be inclusive of Ancillary Service Offers. |

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| ***[NPRR1188: Insert Section 4.4.9.8 below upon system implementation:]***  **4.4.9.8 Energy Bid Curves**  (1) An Energy Bid Curve represents the willingness to buy energy at or below a certain price, not to exceed the effective Value of Lost Load (VOLL) for the Demand response capability of a CLR in the DAM or the RTM.  (2) An Energy Bid Curve remains active for the offered period until automatically inactivated at the offer expiration time specified in the Energy Bid Curve.  (3) For any Operating Hour, the QSE may submit or change an Energy Bid Curve at any time prior to SCED execution, and SCED will use the latest updated Energy Bid Curve available in the system. If a new Energy Bid Curve is not deemed to be valid, then the most recent valid Energy Bid Curve available in the system at the time of SCED execution will be used and ERCOT will notify the QSE that the invalid Energy Bid Curve was rejected.  (4) Once an Operating Hour ends, an Energy Bid Curve for that hour cannot be submitted, updated, or canceled. |

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| ***[NPRR1188: Insert Section 4.4.9.8.1 below upon system implementation:]***  ***4.4.9.8.1 Energy Bid Curve Criteria***  (1) Each Energy Bid Curve submitted by a QSE must include the following information:  (a) The submitting QSE’s name;  (b) The Load Resource’s name;  (c) A bid curve with no more than ten price/quantity pairs with monotonically non-increasing not-to-exceed prices (in $/MWh), no more than two consecutive price/quantity pairs at the same price, and with increasing quantities ranging from zero to the Load Resource’s maximum demand response capability (in MW) represented by the difference between the Load Resource’s telemetered Maximum Power Consumption (MPC) and Low Power Consumption (LPC);  (d) The first and last hour of the bid; and  (e) The expiration time and date of the bid.  (2) The software systems must be able to provide ERCOT with the ability to enter Resource-specific Energy Bid Curve floors and caps.  (3) The minimum amount that may be submitted per Load Resource for each Energy Bid Curve is one-tenth (0.1) MW.  (4) Prices included in the submitted Energy Bid Curve may not exceed the effective Value of Lost Load (VOLL). |

**6.3 Adjustment Period and Real-Time Operations Timeline**

(1) The figure below highlights the major activities that occur in the Adjustment Period and Real-Time operations:

**QSE Deadline:**

**Update Energy Bids and Offers**

**Submit HRUC Offers**

**Update Output Schedules**

**Update Inc/Dec Offers for**

**DSRs**

**ERCOT Activity:**

**LFC Process every 4 secs**

**Execute SCED every 5**

**mins**

**Communicate Instructions**

**& Prices**

**ERCOT Activity:**

**Snapshot Inputs &**

**Execute HRUC**

**Operating Period**

**Operating Hour**

**Clock**

**Hour**

**T**

**Adjustment Period & Real**

**-**

**Time Operations**

**Real**

**-**

**Time**

**Operations**

**QSE Deadline:**

**Update Output Schedules for**

**DSRs**

**Provide SCADA Telemetry**

**ERCOT Activity:**

**Communicate**

**HRUC Commitments**

(2) Activities for the Adjustment Period begin at 1800 in the Day-Ahead and end one full hour before the start of the Operating Hour. The figure above is intended to be only a general guide and not controlling language, and any conflict between this figure and another section of the Protocols is controlled by the other section.

(3) ERCOT shall monitor Real-Time Locational Marginal Prices (LMPs), Supplemental Ancillary Services Market (SASM) Market Clearing Prices for Capacity (MCPCs), and Real-Time Settlement Point Prices, including Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Off-Line Reserve Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Reserve Prices for On-Line Reserves and Real-Time Reserve Prices for Off-Line Reserves, for errors and if there are conditions that cause the price to be questionable, ERCOT shall notify all Market Participants that the Real-Time LMPs, SASM MCPCs, and Real-Time Settlement Point Prices are under investigation as soon as practicable.

(4) ERCOT shall correct prices for an Operating Day when accurate prices can be determined, the impact of the price correction is determined to be significant, and one of the following conditions has been met: a market solution is determined to be invalid, invalid prices are identified in an otherwise valid market solution, the Base Points received by Market Participants are inconsistent with the Base Points of a valid market solution, or the Security-Constrained Economic Dispatch (SCED) process experiences a failure as described in Section 6.5.9.2, Failure of the SCED Process. The following are some reasons that may cause these conditions:

(a) Data Input error: Missing, incomplete, stale, or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices.

(b) Data Output error: These include: incorrect or incomplete data transfer, price recalculation error in post-processing, and Base Points inconsistent with prices due to the Emergency Base Point flag remaining activated even when the SCED solution is valid.

(c) Hardware/Software error: These include unpredicted hardware or software failures, planned market system or database outages, planned application or database upgrades, software implementation errors, and failure of the market run to complete.

(d) Inconsistency with the Protocols or Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.

(5) For purposes of a price correction performed prior to 1600 on the second Business Day after the Operating Day, the impact of a price correction shall be considered significant, as that term is used in paragraph (4) above, for the Operating Day when:

(a) The absolute value change to any single Real-Time Settlement Point Price at a Resource Node is greater than $0.05/MWh;

(b) The price correction would require ERCOT to change more than 50 Real-Time Settlement Point Prices;

(c) The absolute value change to any Real-Time Settlement Point Price at a Load Zone or Hub is greater than $0.02/MWh;

(d) The estimated absolute total dollar impact for changes to Real-Time prices for energy metered is greater than $500; or

(e) The absolute total dollar impact for changes to SASM MCPCs is greater than $500.

(6) If it is determined that any Real-Time Settlement Point Prices, Settlement Point LMPs, Electrical Bus LMPs, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, and/or constraint Shadow Prices are erroneous, ERCOT shall correct the prices before the prices are considered final in paragraph (7) below. Specifically:

(a) If it is determined that correcting the Real-Time Settlement Point Prices will not affect the Base Points that were received by Qualified Scheduling Entities (QSEs), then ERCOT shall correct the prices before the prices are considered final in paragraph (7) below.

(b) If it is determined that correcting the Real-Time Settlement Point Prices will affect the Base Points that were received by QSEs, then ERCOT shall correct the prices before the prices are considered final and settle the SCED executions as failed in accordance with Section 6.5.9.2.

(c) If the Base Points received by QSEs are inconsistent with the Real-Time Settlement Point Prices reduced by the sum of the Real-Time On-Line Reliability Deployment Prices and the Real-Time Reserve Prices for On-Line Reserves averaged over the 15-minute Settlement Interval, then ERCOT shall consider those Base Points as due to manual override from the ERCOT Operator and settle the relevant Settlement Interval(s) in accordance with Section 6.6.9, Emergency Operations Settlement.

(7) All Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs are final at 1600 of the second Business Day after the Operating Day.

(a) However, after Real-Time LMPs, Real Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs are final, if ERCOT determines that prices qualify for a price correction pursuant to paragraph (4) above and that ERCOT will seek ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:

(i) ERCOT’s duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;

(ii) The PUCT’s authority to order price corrections when permitted to do so under other law; or

(iii) ERCOT’s authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure and Procedure for Return of Settlement Funds.

(b) Before seeking ERCOT Board review of prices, ERCOT will determine if the impact of the price correction is significant, as that term is used in paragraph (4) above, by calculating the potential changes to the Real-Time Market (RTM) Settlement Statement(s) of any Counter-Party on a given Operating Day. ERCOT shall seek ERCOT Board review of prices if the change in RTM Settlement Statement(s) would result in the absolute value impact to any single Counter-Party, based on the sum of all original RTM Settlement Statement amounts of Market Participants assigned to the Counter-Party, to be greater than:

(i) 2% and also greater than $20,000; or

(ii) 20% and also greater than $2,000.

(c) The ERCOT Board may review and change Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices, Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices should be corrected for an Operating Day.

(d) In review of Real-Time LMPs, Real Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reliability Deployment Prices,Real-Time Reserve Prices for On-Line Reserves, Real-Time Reserve Prices for Off-Line Reserves, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders and SASM MCPCs, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices should be corrected for an Operating Day.

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| ***[NPRR1000, NPRR1010, NPRR1014, and NPRR1245: Replace applicable portions of Section 6.3 above with the following upon system implementation for NPRR1000 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1245:]***  **6.3 Adjustment Period and Real-Time Operations Timeline**  (1) The figure below highlights the major activities that occur in the Adjustment Period and Real-Time operations:  **Preparation for**  **Real**  **-**  **Time Ops**  **Adj Period**  **18:00**  **(D**  **–**  **1)**  **60 Minutes**  **Prior to**  **Op Hour**  **QSE Deadline:**  **Update Energy Bids and Offers**  **Update Output Schedules**  **ERCOT Activity:**  **LFC Process every 4 secs**  **Execute SCED every 5**  **mins**  **Communicate Instructions,**  **Awards & Prices**  **ERCOT Activity:**  **Snapshot Inputs &**  **Execute HRUC**  **Operating Period**  **Operating Hour**  **Clock**  **Hour**  **T**  **Adjustment Period & Real**  **-**  **Time Operations**  **Real**  **-**  **Time**  **Operations**  **QSE Deadline:**  **Update AS Offers**  **Provide SCADA Telemetry**  **Update Energy Bid/Offer Curves**  **ERCOT Activity:**  **Communicate**  **HRUC Commitments**  (2) Activities for the Adjustment Period begin at 1800 in the Day-Ahead and end one full hour before the start of the Operating Hour. The figure above is intended to be only a general guide and not controlling language, and any conflict between this figure and another section of the Protocols is controlled by the other section.  (3) ERCOT shall monitor Real-Time Locational Marginal Prices (LMPs), Real-Time Market Clearing Prices for Capacity (MCPCs), and Real-Time Settlement Point Prices, including Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, for errors and if there are conditions that cause the price to be questionable, as soon as practicable, ERCOT shall notify all Market Participants that the Real-Time LMPs, Real-Time MCPCs, and Real-Time Settlement Point Prices are under investigation.  (4) ERCOT shall correct prices for an Operating Day when accurate prices can be determined, the impact of the price correction is determined to be significant, and one of the following conditions has been met: a market solution is determined to be invalid, invalid prices are identified in an otherwise valid market solution, the Base Points or Ancillary Service awards received by Market Participants are inconsistent with the Base Points or Ancillary Service awards of a valid market solution, or the Security-Constrained Economic Dispatch (SCED) process experiences a failure as described in Section 6.5.9.2, Failure of the SCED Process. The following are some reasons that may cause these conditions.  (a) Data Input error: Missing, incomplete, stale, or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices.  (b) Data Output error: These include: incorrect or incomplete data transfer, price recalculation error in post-processing, and Base Points inconsistent with prices due to the Emergency Base Point flag remaining activated even when the SCED solution is valid.  (c) Hardware/Software error: These include unpredicted hardware or software failures, planned market system or database outages, planned application or database upgrades, software implementation errors, and failure of the market run to complete.  (d) Inconsistency with the Protocols or Public Utility Commission of Texas (PUCT) Substantive Rules: Pricing errors may occur when specific circumstances result in prices that are in conflict with such Protocol language or the PUCT Substantive Rules.  (5) For purposes of a price correction performed prior to 1600 on the second Business Day after the Operating Day, the impact of a price correction shall be considered significant, as that term is used in paragraph (4) above, for the Operating Day when:  (a) The absolute value change to any single Real-Time Settlement Point Price at a Resource Node or Real-Time MCPC is greater than $0.05/MWh;  (b) The price correction would require ERCOT to change more than 50 Real-Time Settlement Point Prices and/or Real-Time MCPCs;  (c) The absolute value change to any Real-Time Settlement Point Price at a Load Zone or Hub is greater than $0.02/MWh; or  (d) The estimated absolute total dollar impact for changes to Real-Time prices for energy metered is greater than $500.  (6) If it is determined that any Real-Time Settlement Point Prices, Settlement Point LMPs, Electrical Bus LMPs, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders for Ancillary Service, and/or constraint Shadow Prices are erroneous, ERCOT shall correct the prices before the prices are considered final in paragraph (7) below. Specifically:  (a) If it is determined that correcting the Real-Time Settlement Point Prices will not affect the Base Points, and correcting Real-Time MCPCs will not affect Ancillary Service awards, then ERCOT shall correct the prices before the prices are considered final in paragraph (7) below.  (b) If it is determined that correcting the Real-Time Settlement Point Prices will affect the Base Points, or correcting Real-Time MCPCs will affect Ancillary Service awards, then ERCOT shall correct the prices before the prices are considered final and settle the SCED executions as failed in accordance with Section 6.5.9.2.  (c) For Settlement purposes, if the Base Points are inconsistent with the Real-Time LMPs, ignoring the Real-Time Reliability Deployment Price Adder for Energy, or Ancillary Service awards are inconsistent with the Real-Time MCPCs, ignoring the Real-Time Reliability Deployment Price Adder for Ancillary Service, averaged over the 15-minute Settlement Interval, then ERCOT shall consider the relevant Settlement Interval(s) in accordance with Section 6.6.9, Emergency Operations Settlement.  (7) All Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service are final at 1600 of the second Business Day after the Operating Day.  (a) However, after Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service are final, if ERCOT determines that prices qualify for a price correction pursuant to paragraph (4) above and that ERCOT will seek ERCOT Board review of such prices, it shall notify Market Participants and describe the need for such correction as soon as practicable but no later than 30 days after the Operating Day. Failure to notify Market Participants within this timeline precludes the ERCOT Board from reviewing such prices. However, nothing in this section shall be understood to limit or otherwise inhibit any of the following:  (i) ERCOT’s duty to inform the PUCT of potential or actual violations of the ERCOT Protocols or PUCT Rules and its right to request that the PUCT authorize correction of any prices that may have been affected by such potential or actual violations;  (ii) The PUCT’s authority to order price corrections when permitted to do so under other law; or  (iii) ERCOT’s authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure and Procedure for Return of Settlement Funds.  (b) Before seeking ERCOT Board review of prices, ERCOT will determine if the impact of the price correction is significant, as that term is used in paragraph (4) above, by calculating the potential changes to the RTM Settlement Statement(s) of any Counter-Party on a given Operating Day. ERCOT shall seek ERCOT Board review of prices if the change in RTM Settlement Statement(s) would result in the absolute value impact to any single Counter-Party, based on the sum of all original RTM Settlement Statement amounts of Market Participants assigned to the Counter-Party, to be greater than:  (i) 2% and also greater than $20,000; or  (ii) 20% and also greater than $2,000.  (c) The ERCOT Board may review and change Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices should be corrected for an Operating Day.  (d) In review of Real-Time LMPs, Real-Time Settlement Point Prices, Real-Time prices for energy metered, Real-Time Reliability Deployment Price Adders for Energy, Real-Time MCPCs, and Real-Time Reliability Deployment Price Adders for Ancillary Service, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices should be corrected for an Operating Day. |

**6.5.5.2** **Operational Data Requirements**

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

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

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

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

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

(d) Net Reactive Power (in MVAr);

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

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

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

(h) Generation Resource breaker and switch status;

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

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

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

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

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

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

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

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

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

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

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

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

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

(s) For an ESR, the next Operating Hour’s Ancillary Service Resource Responsibility for each quantity of Reg-Up, Reg-Down, ECRS, RRS and Non-Spin.

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

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

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| * ***[NPRR1270: Insert paragraph (4) below upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]***   (4) For each Resource, the QSE for the Resource shall consider the physical capability to provide a specific type of Ancillary Service based on the operating conditions for that specific Ancillary Service, including equipment availability, weather conditions and ability to meet the Ancillary Service criteria specified in Section 8.1.1.3, Ancillary Service Capacity Compliance Criteria. ERCOT may perform validation of the QSE’s submission to ensure these criteria are considered and adhered to. |

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

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

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

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

(c) Load Resource breaker status, if applicable;

(d) LPC (in MW);

(e) MPC (in MW);

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

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

(h) The status of the high-set under-frequency relay, if required for qualification. The under-frequency relay for a Load Resource providing Non-Spin shall be disabled and the status of that relay shall indicate it as disabled or unarmed;

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

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

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

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

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

(n) For an ESR, the next Operating Hour’s Ancillary Service Resource Responsibility for each quantity of Reg-Up, Reg-Down, ECRS, RRS and Non-Spin.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) Combustion turbine inlet air cooling methods;

(b) Duct firing;

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

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

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

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

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

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

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

(c) State of Charge (SOC), in MWh;

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

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

(13) The QSE shall ensure that the SOC is greater than or equal to the MinSOC and less than or equal to the MaxSOC.

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

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| ***[NPRR1077: Insert paragraphs (15)-(17) below upon system implementation:]***  (15) Except as provided in paragraph (15) below, a QSE representing a Settlement Only Generator (SOG) shall provide ERCOT the following Real-Time telemetry:  (a) Net real power injection at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for each site with one or more SOGs;  (b) For any site with one or more ESSs that are registered as an SOG, net real power withdrawal at the POI or POCC;  (c) For each inverter at the site, gross real power output measured at the generator terminals for all SOGs that are located behind that inverter, separately aggregated by fuel type;  (d) For SOGs at the same site that are not located behind an inverter, gross real power output measured at the generator terminals for all SOGs, separately aggregated by fuel type;  (e) For any site with one or more ESSs registered as an SOG, for each inverter, gross real power withdrawal by all such ESSs that are located behind that inverter, as measured at the generator terminals; and  (f) Generator breaker status.  (16) A QSE is not required to provide telemetry for a Settlement Only Distribution Generator (SODG) if:  (a) The site that includes the SODG has not exported more than 10 MWh in any calendar year, exclusive of any energy exported during any Settlement Interval in which an ERCOT-declared Energy Emergency Alert (EEA) is in effect;  (b) The QSE or Resource Entity for the SODG has submitted a written request to ERCOT seeking an exemption from the telemetry requirements under this paragraph; and  (c) ERCOT has provided the QSE or Resource Entity written confirmation that the SODG is exempt from providing telemetry under this paragraph.  (17) If ERCOT determines that a site that includes an SODG has exported more than 10 MWh in a given calendar year, it shall notify the SODG’s QSE that the SODG is no longer eligible for the telemetry exemption. Within 90 days of receiving this notification, the QSE for the SODG shall comply with the telemetry requirements of paragraph (14) above. |

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| ***[NPRR885: Insert paragraph (18) below upon system implementation:]***  (18) A QSE representing a Must-Run Alternative (MRA) shall telemeter the MRA MW currently available (unloaded) and not included in the HSL. |

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| ***[NPRR1029: Insert paragraph (19) below upon system implementation:]***  (19) A QSE representing a DC-Coupled Resource shall provide the following Real-Time telemetry data in addition to that required for other ESRs:  (a) Gross AC MW production of the intermittent renewable generation component of the DC-Coupled Resource, which includes the portion of the intermittent renewable generation used to charge the ESS and/or serve auxiliary Load on the DC side of the inverter; and  (b) Gross AC MW capability of the intermittent renewable generation component of the DC-Coupled Resource, based on Real-Time conditions. |

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| ***[NPRR995: Insert paragraph (20) below upon system implementation:]***  (20) A QSE representing a Settlement Only Energy Storage System (SOESS) that elects to include the net generation and/or net withdrawals of the SOESS in the estimate of Real-Time Liability (RTL) shall provide ERCOT Real-Time telemetry of the net generation and/or net withdrawals of the SOESS. |

**6.5.7.3 Security Constrained Economic Dispatch**

(1) The SCED process is designed to simultaneously manage energy, the system power balance and network congestion through Resource Base Points and calculation of LMPs every five minutes. The SCED process uses a two-step methodology that applies mitigation prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Output Schedules and Real-Time Market (RTM) Energy Bids to determine Resource Dispatch Instructions by maximizing bid-based revenues minus offer-based costs, subject to power balance and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP.

(2) The SCED solution must monitor cumulative deployment of Regulation Services and ensure that Regulation Services deployment is minimized over time.

(3) In the Generation To Be Dispatched (GTBD) determined by LFC, ERCOT shall subtract the sum of the telemetered net real power consumption from all CLRs available to SCED.

(4) For use as SCED inputs, ERCOT shall use the available capacity of all committed Generation Resources by creating proxy Energy Offer Curves for certain Resources as follows:

(a) Non-IRRs and Dynamically Scheduled Resources (DSRs) without Energy Offer Curves

(i) ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below for:

(A) Each non-IRR for which its QSE has submitted an Output Schedule instead of an Energy Offer Curve; and

(B) Each DSR that has not submitted incremental and decremental Energy Offer Curves.

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| **MW** | **Price (per MWh)** |
| HSL | SWCAP |
| Output Schedule MW plus 1 MW | SWCAP minus $0.01 |
| Output Schedule MW | -$249.99 |
| LSL | -$250.00 |

(b) DSRs with Energy Offer Curves

(i) For each DSR that has submitted incremental and decremental Energy Offer Curves, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve. That curve must consist of the incremental Energy Offer Curve that reflects the available capacity above the Resource’s Output Schedule to its HSL and the decremental Energy Offer Curve that reflects the available capacity below the Resource’s Output Schedule to the LSL. The curve must be created as described below:

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| **MW** | **Price (per MWh)** |
| Output Schedule MW plus 1 MW to HSL | Incremental Energy Offer Curve |
| LSL to Output Schedule MW | Decremental Energy Offer Curve |

(c) Non-IRRs without full-range Energy Offer Curves

(i) For each non-IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the Resource’s available capacity, ERCOT shall create a proxy Energy Offer Curve that extends the submitted Energy Offer Curve to use the entire available capacity of the Resource above the highest point on the Energy Offer Curve to the Resource’s HSL and the offer floor from the lowest point on the Energy Offer Curve to its LSL, using these points:

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| **MW** | **Price (per MWh)** |
| HSL (if more than highest MW in submitted Energy Offer Curve) | Price associated with highest MW in submitted Energy Offer Curve |
| Energy Offer Curve | Energy Offer Curve |
| 1 MW below lowest MW in Energy Offer Curve (if more than LSL) | -$249.99 |
| LSL (if less than lowest MW in Energy Offer Curve) | -$250.00 |

(d) IRRs

(i) For each IRR that has not submitted an Energy Offer Curve, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:

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| **MW** | **Price (per MWh)** |
| HSL | $1,500 |
| HSL minus 1 MW | -$249.99 |
| LSL | -$250.00 |

(ii) For each IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the IRR’s available capacity, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:

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| --- | --- |
| **MW** | **Price (per MWh)** |
| HSL (if more than highest MW in submitted Energy Offer Curve) | Price associated with the highest MW in submitted Energy Offer Curve |
| Energy Offer Curve | Energy Offer Curve |
| 1 MW below lowest MW in Energy Offer Curve (if more than LSL) | -$249.99 |
| LSL (if less than lowest MW in Energy Offer Curve) | -$250.00 |

(e) RUC-committed Resources

(i) For each RUC-committed Resource that has not submitted an Energy Offer Curve, ERCOT shall create a proxy Energy Offer Curve as described below:

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| --- | --- |
| **MW** | **Price (per MWh)** |
| HSL | $250 |
| Zero | $250 |

(ii) For each RUC-committed Resource that has submitted an Energy Offer Curve, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:

|  |  |
| --- | --- |
| **MW** | **Price (per MWh)** |
| HSL (if more than highest MW in Energy Offer Curve) | Greater of $250 or price associated with the highest MW in QSE submitted Energy Offer Curve |
| Energy Offer Curve | Greater of $250 or the QSE submitted Energy Offer Curve |
| Zero | Greater of $250 or the first price point of the QSE submitted Energy Offer Curve |

(iii) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

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| --- | --- |
| **MW** | **Price (per MWh)** |
| HSL of RUC-committed configuration | $250 |
| Zero | $250 |

(iv) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:

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| --- | --- |
| **MW** | **Price (per MWh)** |
| HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve) | Greater of $250 or price associated with the highest MW in QSE submitted Energy Offer Curve |
| Energy Offer Curve for MW at and above HSL of QSE-committed configuration | Greater of $250 or the QSE submitted Energy Offer Curve |
| HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than $250) | $250 |
| HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve) | Price associated with the highest MW in QSE submitted Energy Offer Curve |
| Energy Offer Curve for MW at and below HSL of QSE-committed configuration | The QSE submitted Energy Offer Curve |
| 1 MW below lowest MW in Energy Offer Curve (if more than LSL) | -$249.99 |
| LSL (if less than lowest MW in Energy Offer Curve) | -$250.00 |

(5) The Entity with decision making authority, as more fully described in Section 3.19.1, Constraint Competitiveness Test Definitions, over how a Resource or Split Generation Resource is offered or scheduled, shall be responsible for all offers associated with each Resource, including offers represented by a proxy Energy Offer Curve.

(6) For a CLR whose QSE has submitted an RTM Energy Bid that does not cover the full range of the Resource’s available Demand response capability, consistent with the CLR’s telemetered quantities, ERCOT shall create a proxy energy bid as described below:

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| **MW** | **Price (per MWh)** |
| LPC to MPC minus maximum MW of RTM Energy Bid | Price associated with the lowest MW in submitted RTM Energy Bid curve |
| MPC minus maximum MW of RTM Energy Bid to MPC | RTM Energy Bid curve |
| MPC | Right-most point (lowest price) on RTM Energy Bid curve |

(7) ERCOT shall ensure that any RTM Energy Bid is monotonically non-increasing. The QSE representing the CLR shall be responsible for all RTM Energy Bids, including bids updated by ERCOT as described above.

(8) If a CLR telemeters a status of OUTL, it is not considered as dispatchable capacity by SCED. A QSE may use this function to inform ERCOT of instances when the CLR is unable to follow SCED Dispatch Instructions. Under all telemetered statuses including OUTL, the remaining telemetry quantities submitted by the QSE shall represent the operating conditions of the CLR that can be verified by ERCOT. A QSE representing a CLR with a telemetered status of OUTL is still obligated to provide any applicable Ancillary Service Resource Responsibilities previously awarded to that CLR. This paragraph does not apply to ESRs.

(9) Energy Offer Curves that were constructed in whole or in part with proxy Energy Offer Curves shall be so marked in all ERCOT postings or references to the energy offer.

(10) The two-step SCED methodology referenced in paragraph (1) above is:

(a) The first step is to execute the SCED process to determine Reference LMPs. In this step, ERCOT executes SCED using the full Network Operations Model while only observing limits of Competitive Constraints. Energy Offer Curves for all On-Line Generation Resources and RTM Energy Bids from available CLRs, whether submitted by QSEs or created by ERCOT under this Section, are used in the SCED to determine “Reference LMPs.”

(b) The second step is to execute the SCED process to produce Base Points, Shadow Prices, and LMPs, subject to security constraints (including Competitive and Non-Competitive Constraints) and other Resource constraints. The second step must:

(i) Use Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT. Each Energy Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. In addition, each Energy Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource’s Mitigated Offer Cap (MOC) curve at the LSL or the appropriate MOC;

(ii) Use RTM Energy Bid curves for all available CLRs, whether submitted by QSEs or created by ERCOT. There is no mitigation of RTM Energy Bids. An RTM Energy Bid from a CLR represents the bid for energy distributed across all nodes in the Load Zone in which the CLR is located. For an ESR, an RTM Energy Bid represents a bid for energy at the ESR’s Resource Node; and

(iii) Observe all Competitive and Non-Competitive Constraints.

(c) ERCOT shall archive information and provide monthly summaries of security violations and any binding transmission constraints identified in Step 2 of the SCED process. The summary must describe the limiting element (or identified operator-entered constraint with operator’s comments describing the reason and the Resource-specific impacts for any manual overrides). ERCOT shall provide the summary to Market Participants on the MIS Secure Area and to the Independent Market Monitor (IMM).

(11) For each SCED process, in addition to the binding Base Points and LMPs, ERCOT shall calculate a non-binding projection of the Base Points and Resource Node LMPs, Real-Time Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Hub LMPs and Load Zone LMPs at a frequency of every five minutes for at least 15 minutes into the future based on the same inputs to the SCED process as described in this Section, except that the Resource’s HDL and LDL and the total generation requirement will be as estimated at future intervals. The Resource’s HDL and LDL will be calculated for each interval of the projection based on the ramp rate capability over the study period. ERCOT shall estimate the projected total generation requirement by calculating a Load forecast for the study period. In lieu of the steps described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the non-binding projection of Real-Time Reliability Deployment Price Adders shall be estimated based on GTBD, reliability deployments MWs, and aggregated offers. The Energy Offer Curve from SCED Step 2, the virtual offers for Load Resources deployed and the power balance penalty curve will be compared against the updated GTBD to get an estimate of the System Lambda from paragraph (2)(m) of Section 6.5.7.3.1. ERCOT shall post the projected non-binding Base Points for each Resource for each interval study period on the MIS Certified Area and the projected non-binding LMPs for Resource Nodes, Real-Time Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Hub LMPs and Load Zone LMPs on the ERCOT website pursuant to Section 6.3.2, Activities for Real-Time Operations.

(12) For each SCED process, ERCOT shall calculate a Real-Time On-Line Reserve Price Adder and a Real-Time Off-Line Reserve Price Adder based on the On-Line and Off-Line available reserves in the ERCOT System and the Operating Reserve Demand Curve (ORDC). The Real-Time Off-Line available reserves shall be administratively set to zero when the SCED snapshot of the Physical Responsive Capability (PRC) is equal to or below the PRC MW at which Energy Emergency Alert (EEA) Level 1 is initiated. In addition, for each SCED process, ERCOT shall calculate a Real-Time On-Line Reliability Deployment Price Adder. The sum of the Real-Time Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder shall be averaged over the 15-minute Settlement Interval and added to the Real-Time LMPs to determine the Real-Time Settlement Point Prices. The price after the addition of the sum of the Real-Time On-Line Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder to LMPs approximates the pricing outcome of the impact to energy prices from reliability deployments and the Real-Time energy and Ancillary Service co-optimization since the Real-Time On-Line Reserve Price Adder captures the value of the opportunity cost of reserves based on the defined ORDC. An Ancillary Service imbalance Settlement shall be performed pursuant to Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge, to make Resources indifferent to the utilization of their capacity for energy or Ancillary Service reserves.

(13) ERCOT shall determine the methodology for implementing the ORDC to calculate the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder. Following review by TAC, the ERCOT Board shall review the recommendation and approve a final methodology. Within two Business Days following approval by the ERCOT Board, ERCOT shall post the methodology on the ERCOT website.

(14) At the end of each season, ERCOT shall determine the ORDC for the same season in the upcoming year, based on historic data using the ERCOT Board-approved methodology for implementing the ORDC. Annually, ERCOT shall verify that the ORDC is adequately representative of the loss of Load probability for varying levels of reserves. Twenty days after the end of the Season, ERCOT shall post the ORDC for the same season of the upcoming year on the ERCOT website.

(15) ERCOT may override one or more of a CLR’s parameters in SCED if ERCOT determines that the CLR’s participation is having an adverse impact on the reliability of the ERCOT System.

(16) The QSE representing an ESR, in order to charge the ESR, must submit RTM Energy Bids, and the ESR may withdraw energy from the ERCOT System only when dispatched by SCED to do so. An ESR may telemeter a status of OUTL only if the ESR is in Outage status.

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| ***[NPRR930, NPRR1000, NPRR1010, NPRR1014, NPRR1019, NPRR1188, NPRR1204, NPRR1268, and NPRR1269: Replace applicable portions of Section 6.5.7.3 above with the following upon system implementation for NPRR930, NPRR1000, NPRR1014, NPRR1019, or NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010, NPRR1204, NPRR1268, and NPRR1269:]***  **6.5.7.3 Security Constrained Economic Dispatch**  (1) The SCED process is designed to simultaneously manage energy, Ancillary Services, the system power balance and network congestion through Resource Base Points, Ancillary Service awards, and the calculation of LMPs and Real-Time MCPCs approximately every five minutes, or more frequently if necessary. The SCED process uses a two-step methodology that applies mitigation to offers for energy prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Energy Bid/Offer Curves, Ancillary Service Offers, Output Schedules, and Energy Bid Curves to determine Resource Dispatch Instructions and Ancillary Service awards by maximizing bid-based revenues minus offer-based costs, subject to power balance, Ancillary Service Demand Curves (ASDCs), and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP. In addition, the SCED process accounts for each ESR’s State of Charge (SOC) and SOC operating limits. This is to ensure that the SCED process will issue ESR Base Points and Ancillary Services that are feasible taking into account SCED duration requirements for energy and Ancillary Services and also that do not violate the ESR’s Minimum State of Charge (MinSOC) and Maximum State of Charge (MaxSOC) limits.  (2) The SCED solution must monitor cumulative deployment of Regulation Services and ensure that Regulation Services deployment is minimized over time.  (3) In the Generation To Be Dispatched (GTBD) determined by LFC, ERCOT shall subtract the sum of the telemetered net real power consumption from all CLRs available to SCED.  (4) For use as SCED inputs for determining energy dispatch and Ancillary Service awards, ERCOT shall use the available capacity of all committed Generation Resources by creating proxy Energy Offer Curves for certain Resources as follows:  (a) Non-IRRs without Energy Offer Curves  (i) ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below for:  (A) Each non-IRR for which its QSE has submitted an Output Schedule instead of an Energy Offer Curve.   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL | RTSWCAP | | Output Schedule MW plus 1 MW | RTSWCAP minus $0.01 | | Output Schedule MW | -$249.99 | | LSL | -$250.00 |   (b) Non-IRRs without full-range Energy Offer Curves  (i) For each non-IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the Resource’s available capacity, ERCOT shall create a proxy Energy Offer Curve that extends the submitted Energy Offer Curve to use the entire available capacity of the Resource above the highest point on the Energy Offer Curve to the Resource’s HSL and the offer floor from the lowest point on the Energy Offer Curve to its LSL, using these points:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL (if more than highest MW in submitted Energy Offer Curve) | Price associated with highest MW in submitted Energy Offer Curve | | Energy Offer Curve | Energy Offer Curve | | 1 MW below lowest MW in Energy Offer Curve (if more than LSL) | -$249.99 | | LSL (if less than lowest MW in Energy Offer Curve) | -$250.00 |   (c) IRRs  (i) For each IRR that has not submitted an Energy Offer Curve, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL | $1,500 | | HSL minus 1 MW | -$249.99 | | LSL | -$250.00 |   (ii) For each IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the IRR’s available capacity, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL (if more than highest MW in submitted Energy Offer Curve) | Price associated with the highest MW in submitted Energy Offer Curve | | Energy Offer Curve | Energy Offer Curve | | 1 MW below lowest MW in Energy Offer Curve (if more than LSL) | -$249.99 | | LSL (if less than lowest MW in Energy Offer Curve) | -$250.00 |   (d) RUC-committed Resources  (i) For each RUC-committed Resource that has not submitted an Energy Offer Curve, ERCOT shall create a proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL | $250 | | Zero | $250 |   (ii) For each RUC-committed Resource that has submitted an Energy Offer Curve, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL (if more than highest MW in Energy Offer Curve) | Greater of $250 or price associated with the highest MW in QSE submitted Energy Offer Curve | | Energy Offer Curve | Greater of $250 or the QSE submitted Energy Offer Curve | | Zero | Greater of $250 or the first price point of the QSE submitted Energy Offer Curve |   (iii) For each RUC-committed Resource during the time period stated in the Advance Action Notice (AAN) if any Resource received an Outage Schedule Adjustment, ERCOT shall create a proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL | $4,500 or the effective Value of Lost Load (VOLL), whichever is less. | | Zero | $4,500 or the effective VOLL, whichever is less. |   (iv) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL of RUC-committed configuration | $250 | | Zero | $250 |   (v) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a monotonically non-decreasing proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve) | Greater of $250 or price associated with the highest MW in QSE submitted Energy Offer Curve | | Energy Offer Curve for MW at and above HSL of QSE-committed configuration | Greater of $250 or the QSE submitted Energy Offer Curve | | HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than $250) | $250 | | HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve) | Price associated with the highest MW in QSE submitted Energy Offer Curve | | Energy Offer Curve for MW at and below HSL of QSE-committed configuration | The QSE submitted Energy Offer Curve | | 1 MW below lowest MW in Energy Offer Curve (if more than LSL) | -$249.99 | | LSL (if less than lowest MW in Energy Offer Curve) | -$250.00 |   (vi) For each RUC-committed Switchable Generation Resource (SWGR) that is not part of a Combined Cycle Train already operating in ERCOT, that has not submitted an Energy Offer Curve, and that has a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of the RUC instruction, ERCOT shall create a proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL | $4,500 or the effective Value of Lost Load (VOLL), whichever is less | | Zero | $4,500 or the effective VOLL, whichever is less |   (vii) For each RUC-committed SWGR that is not part of a Combined Cycle Train already operating in ERCOT, that has submitted an Energy Offer Curve, and that has a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of the RUC instruction, ERCOT shall create a proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL (if more than highest MW in Energy Offer Curve) | Greater of: $4,500 or the effective VOLL, whichever is less; and the price associated with the highest MW in QSE-submitted Energy Offer Curve | | Energy Offer Curve | Greater of: $4,500 or the effective VOLL, whichever is less; and the QSE-submitted Energy Offer Curve | | Zero | Greater of: $4,500 or the effective VOLL, whichever is less; and the first price point of the QSE-submitted Energy Offer Curve |   (viii) For each Combined Cycle Train configuration that includes at least one SWGR that is operating in a non-ERCOT Control Area as part of a configuration with a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of a RUC instruction requiring the switching of the SWGR into the ERCOT Control Area, if the QSE for the Combined Cycle Train has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL of RUC-committed configuration | $4,500 or the effective VOLL, whichever is less | | Zero | $4,500 or the effective VOLL, whichever is less |   (ix) For each Combined Cycle Train configuration that includes at least one SWGR that is operating in a non-ERCOT Control Area as part of a configuration with a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of a RUC instruction requiring the switching of the SWGR into the ERCOT Control Area, if the QSE for the Combined Cycle Train has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve) | Greater of: $4,500 or the effective VOLL, whichever is less; and the price associated with the highest MW in QSE-submitted Energy Offer Curve | | Energy Offer Curve for MW at and above HSL of QSE-committed configuration | Greater of: $4,500 or the effective VOLL, whichever is less; and the QSE-submitted Energy Offer Curve | | HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than $4,500) | $4,500 or the effective VOLL, whichever is less | | HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve) | Price associated with the highest MW in QSE-submitted Energy Offer Curve | | Energy Offer Curve for MW at and below HSL of QSE-committed configuration | The QSE-submitted Energy Offer Curve | | 1 MW below lowest MW in Energy Offer Curve (if more than LSL) | -$249.99 | | LSL (if less than lowest MW in Energy Offer Curve) | -$250.00 |   (5) For use as SCED inputs for determining energy dispatch and Ancillary Service awards, ERCOT shall use the available Ancillary Service MW capacity of all Resources by creating a proxy Ancillary Service Offer for qualified Resources as follows:  (a) The proxy Ancillary Service Offer shall be a linked Ancillary Service Offer across all Ancillary Service products for which a Resource is qualified to provide. For Generation Resources, the proxy Ancillary Service Offer MW shall be equal to the Resource’s telemetered HSL. For ESRs, the proxy Ancillary Service Offer MW shall be equal to the difference between the Resource’s telemetered HSL and LSL. For Load Resources, the proxy Ancillary Service Offer MW shall be equal to the Resource’s telemetered Maximum Power Consumption (MPC).  (b) For Resources that are not RUC-committed, the price in the proxy Ancillary Service Offer shall be set to:  (i) For Reg-Up and RRS, the maximum of:  (A) The proxy Ancillary Service Offer price floor for Reg-Up or RRS, respectively;  (B) The Resource’s highest submitted Ancillary Service Offer price for Reg-Up or RRS, respectively;  (C) The Resource’s highest Ancillary Service Offer price for ECRS (submitted or proxy); or  (D) The Resource’s highest Ancillary Service Offer price for Non-Spin (submitted or proxy).  (ii) For ECRS, the maximum of:  (A) The proxy Ancillary Service Offer price floor for ECRS;  (B) The Resource’s highest submitted Ancillary Service Offer price for ECRS; or  (C) The Resource’s highest Ancillary Service Offer price for Non-Spin (submitted or proxy).  (iii) For Non-Spin, the maximum of:  (A) The proxy Ancillary Service Offer price floor for Non-Spin; or  (B) The Resource’s highest submitted Ancillary Service Offer price for Non-Spin.  (iv) For Reg-Down, the maximum of:  (A) The proxy Ancillary Service Offer price floor for Reg-Down; or  (B) The Resource’s highest submitted Ancillary Service Offer price for Reg-Down.  (c) The proxy Ancillary Service Offer price floors for each SCED-interval shall be derived from the effective ASDCs and Ancillary Service Plan using the following logic:  (i) The proxy Ancillary Service Offer price floor for Reg-Up is equal to the lesser of the values below minus $0.01 per MW per hour:  (A) $2,000 per MW per hour; or  (B) The point on the ASDC for Reg-Up that intersects with a quantity that is 95% of the Ancillary Service Plan for Reg-Up.  (ii) The proxy Ancillary Service Offer price floor for RRS is equal to the lesser of the values below minus $0.01 per MW per hour:  (A) $2,000 per MW per hour; or  (B) The point on the ASDC for RRS that intersects with a quantity that is 95% of the Ancillary Service Plan for RRS.  (iii) The proxy Ancillary Service Offer price floor for ECRS is equal to the lesser of the values below minus $0.01 per MW per hour:  (A) $2,000 per MW per hour; or  (B) The point on the ASDC for ECRS that intersects with a quantity that is 95% of the Ancillary Service Plan for ECRS.  (iv) The proxy Ancillary Service Offer price floor for Non-Spin is equal to the lesser of the values below minus $0.01 per MW per hour:  (A) $2,000 per MW per hour; or  (B) The point on the ASDC for Non-Spin that intersects with a quantity that is 95% of the Ancillary Service Plan for Non-Spin.  (v) The proxy Ancillary Service Offer price floor for Reg-Down is equal to the lesser of the values below minus $0.01 per MW per hour:  (A) $2,000 per MW per hour; or  (B) The point on the ASDC for Reg-Down that intersects with a quantity that is 95% of the Ancillary Service Plan for Reg-Down.  (d) ERCOT systems shall be designed to allow for proxy Ancillary Service Offer price floors to differ when the same Ancillary Service product can be provided by either On-Line or Off-Line Resources, and/or an Ancillary Service product has sub-types.  (e) For RUC-committed Resources:  (i) If a RUC-committed Resource does not have an Ancillary Service Offer for an Ancillary Service product that the Resource is qualified to provide, ERCOT shall create an Ancillary Service Offer for that Ancillary Service product at a value of $250 per MWh for the full operating range of the Resource up to its telemetered HSL.  (ii) For each Ancillary Service product for which a RUC-committed Resource has an Ancillary Service Offer, the Ancillary Service Offer used by SCED for that Ancillary Service product across the full operating range of the Resource up to its telemetered HSL shall be the maximum of:  (A) The Resource’s highest submitted Ancillary Service Offer price; or  (B) $250 per MWh.  (6) For use as SCED inputs for determining energy Dispatch and Ancillary Service awards, ERCOT shall use the available capacity of all On-Line ESRs by creating proxy Energy Bid/Offer Curves for certain Resources as follows:  (a) For each ESR for which its QSE has submitted an Energy Bid/Offer Curve that does not cover the full offer range (LSL to HSL) of the Resource’s available capacity, ERCOT shall create a proxy Energy Bid/Offer Curve that extends the submitted Energy Bid/Offer Curve to use the entire available capacity of the Resource above the highest MW point on the Energy Bid/Offer Curve to the Resource’s HSL and from the lowest MW point on the Energy Bid/Offer Curve to LSL, using these prices for the corresponding MW segments:   |  |  |  | | --- | --- | --- | | **Scenario** | **MW Segment** | **Price (per MWh)** | | HSL MW and the highest MW point on the Energy Bid/Offer are both greater than or equal to zero,  and,  HSL is greater than the highest MW in submitted Energy Bid/Offer Curve | From highest MW point on submitted Energy Bid/Offer Curve to HSL MW | RTSWCAP | | HSL MW is greater than or equal to zero,  and,  the highest MW point on the Energy Bid/Offer is less than zero | From highest MW point on submitted Energy Bid/Offer Curve to 0 MW  From 0 MW to HSL | Price associated with the highest MW in submitted Energy Bid/Offer Curve  RTSWCAP | | HSL is less than zero and is also greater than the highest MW in submitted Energy Bid/Offer Curve | From highest MW point on submitted Energy Bid/Offer Curve to HSL MW | Price associated with the highest MW in submitted Energy Bid/Offer Curve | | Energy Bid/Offer Curve |  | Energy Bid/Offer Curve | | LSL MW and the lowest MW point on the Energy Bid/Offer Curve are both greater than or equal to zero,  and,  LSL is less than the lowest MW in submitted Energy Bid/Offer Curve | From LSL to lowest MW point on submitted Energy Bid/Offer Curve | Price associated with the lowest MW in submitted Energy Bid/Offer Curve | | LSL MW is less than zero,  and,  the lowest MW point on the Energy Bid/Offer Curve is greater than zero | From LSL to 0 MW  From 0 MW to lowest MW point on submitted Energy Bid/Offer Curve | -$250.00  Price associated with the lowest MW in submitted Energy Bid/Offer Curve | | LSL and the lowest MW point on the Energy Bid/Offer Curve are both less than or equal to zero,  and,  LSL is less than the lowest MW point on the Energy Bid/Offer Curve | From LSL to lowest MW point on submitted Energy Bid/Offer Curve | -$250.00 |   (b) At the time of SCED execution, if a valid Energy Bid/Offer Curve or Output Schedule does not exist for an ESR that has a status of On-Line, then ERCOT shall notify the QSE and create a proxy Energy Bid/Offer Curve priced at -$250/MWh for the MW portion of the curve less than zero MW, and priced at the RTSWCAP for the MW portion of the curve greater than zero MW.  (c) At the time of SCED execution, if a QSE representing an ESR has submitted an Output Schedule instead of an Energy Bid/Offer Curve, ERCOT shall create a proxy Energy Bid/Offer Curve priced at -$250 per MWh for the MW portion of the curve from its LSL to the MW amount on the Output Schedule, and priced at the RTSWCAP for the MW portion of the curve from the MW amount on the Output Schedule to its HSL.  (7) The Entity with decision-making authority, as more fully described in Section 3.19.1, Constraint Competitiveness Test Definitions, over how a Resource or Split Generation Resource is offered or scheduled, shall be responsible for all offers associated with each Resource, including offers represented by a proxy Energy Offer Curve, proxy Energy Bid/Offer Curve, or proxy Ancillary Service Offer.  (8) For a CLR whose QSE has submitted an Energy Bid Curve that does not cover the full range of the Resource’s available Demand response capability, consistent with the CLR’s telemetered quantities, ERCOT shall create a proxy energy bid as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | LPC to MPC minus maximum MW of Energy Bid Curve | Price associated with the lowest MW in submitted Energy Bid Curve | | MPC minus maximum MW of Energy Bid Curve to MPC | Energy Bid Curve | | MPC | Right-most point (lowest price) on Energy Bid Curve |   (9) For a CLR whose QSE has not submitted an Energy Bid Curve, consistent with the CLR’s telemetered quantities, ERCOT shall create a proxy Energy Bid Curve as described below:   |  |  | | --- | --- | | **MW** | **Price (per MWh)** | | LPC to MPC | Effective Value of Lost Load (VOLL) |   (10) ERCOT shall ensure that any Energy Bid Curve is monotonically non-increasing. The QSE representing the CLR shall be responsible for all Energy Bid Curves, including Energy Bid Curves updated by ERCOT as described above.  (11) A CLR may consume energy only when dispatched by SCED to do so. A CLR may telemeter a status of OUTL only if the Resource is Off-Line and unavailable with its energy consumption at zero. In instances when the CLR is unable to follow SCED Dispatch Instructions but still consumes energy, the CLR must submit a Resource Status of ONHOLD. Under all telemetered statuses, including OUTL, the remaining telemetry quantities submitted by the QSE shall represent the operating conditions of the CLR that can be verified by ERCOT. A QSE representing a CLR with a telemetered status of OUTL or ONHOLD is still obligated to provide any applicable Ancillary Services awarded to the Resource. This paragraph does not apply to ESRs.  (12) Energy Offer Curves that were constructed in whole or in part with proxy Energy Offer Curves shall be so marked in all ERCOT postings or references to the energy offer.  (13) SCED will enforce Resource-specific Ancillary Service constraints to ensure that Ancillary Service awards are aligned with a Resource’s qualifications and telemetered Ancillary Service capabilities.  (a) A scaling factor of 5/7 shall be used for Reg-Up award when ensuring that the SCED Base Point plus the product of this scaling factor and the Reg-Up award does not exceed HDL.  (b) A scaling factor of 5/7 shall be used for Reg-Down award when ensuring that the SCED Base Point minus the product of this scaling factor and the Reg-Down award does not go below LDL.  (14) Energy Bid/Offer Curves that were constructed in whole or in part with proxy Energy Bid/Offer Curves shall be so marked in all ERCOT postings or references to the energy bid/offer.  (15) The two-step SCED methodology referenced in paragraph (1) above is:  (a) The first step is to execute the SCED process to determine Reference LMPs. In this step, ERCOT executes SCED using the full Network Operations Model while only observing limits of Competitive Constraints in addition to power balance and Ancillary Service constraints. Energy Offer Curves for all On-Line Generation Resources, Energy Bid/Offer Curves for all On-Line ESRs, and Energy Bid Curves from available CLRs, whether submitted by QSEs or created by ERCOT under this Section, are used in the SCED to determine “Reference LMPs.”  (b) The second step is to execute the SCED process to produce Base Points, Ancillary Service awards, Shadow Prices, Real-Time MCPCs, and LMPs, subject to security constraints (including Competitive and Non-Competitive Constraints) and other Resource constraints. The second step must:  (i) Use Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT. Each Energy Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. In addition, each Energy Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource’s Mitigated Offer Cap (MOC) curve at the LSL or the appropriate MOC;  (ii) Use Energy Bid/Offer Curves for all On-Line ESRs, whether submitted by QSEs or created by ERCOT. Each Energy Bid/Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. The offer portion of each Energy Bid/Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource’s MOC curve at the LSL or the appropriate MOC;  (iii) Use Energy Bid Curves for all available CLRs, whether submitted by QSEs or created by ERCOT. There is no mitigation of Energy Bid Curves. An Energy Bid Curve from an Aggregate Load Resource (ALR) represents the bid for energy distributed across all nodes in the Load Zone in which the ALR is located. For an ESR or a CLR that is not an ALR, an Energy Bid Curve represents a bid for energy at the applicable Resource Node;  (iv) Observe all Competitive and Non-Competitive Constraints; and  (v) Use Ancillary Service Offers to determine Ancillary Service awards.  (c) ERCOT shall archive information and provide monthly summaries of security violations and any binding transmission constraints identified in Step 2 of the SCED process. The summary must describe the limiting element (or identified operator-entered constraint with operator’s comments describing the reason and the Resource-specific impacts for any manual overrides). ERCOT shall provide the summary to Market Participants on the MIS Secure Area and to the Independent Market Monitor (IMM).  (d) The System Lambda used to determine LMPs and the Real-Time MCPCs from SCED Step 2 shall be capped at the effective VOLL. If the following conditions are met for a SCED interval in which the SCED Step 2 System Lambda was capped, a QSE may be eligible for compensation by submitting a Settlement and billing dispute pursuant to paragraph (5) of Section 6.6.9, Emergency Operations Settlement:  (i) A Generation Resource or Energy Storage Resource for the QSE received a Base Point greater than the Resource’s Low Dispatch Limit (LDL) for that SCED interval; and  (ii) The LMP at the Resource is less than the price on the Resource’s Energy Offer Curve or Energy Bid/Offer Curve, as applicable, with any Resource’s Energy Offer Curve or Energy Bid/Offer Curve capped by the Mitigated Offer Cap (MOC).  (16) For each SCED process, in addition to the binding Base Points, Ancillary Service awards, Real-Time MCPCs, and LMPs, ERCOT shall calculate a non-binding projection of the Base Points, Ancillary Service awards, MCPCs, Resource Node LMPs, Real-Time Reliability Deployment Price Adders, Hub LMPs, and Load Zone LMPs at a frequency of every five minutes for at least 15 minutes into the future based on the same inputs to the SCED process as described in this Section, except that the Resource’s HDL and LDL and the total generation requirement will be as estimated at future intervals. The Resource’s HDL and LDL will be calculated for each interval of the projection based on the ramp rate capability over the study period. ERCOT shall estimate the projected total generation requirement by calculating a Load forecast for the study period. In lieu of the steps described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the non-binding projection of Real-Time Reliability Deployment Price Adders shall be estimated based on GTBD, reliability deployments MWs, and aggregated offers. The Energy Offer Curve and Energy Bid/Offer Curves from SCED Step 2, the virtual offers for Load Resources deployed and the power balance penalty price will be compared against the updated GTBD to get an estimate of the System Lambda from paragraph (2)(m) of Section 6.5.7.3.1. ERCOT shall post the projected non-binding Base Points and Ancillary Service awards for each Resource for each interval study period on the MIS Certified Area and the projected non-binding LMPs for Resource Nodes, Real-Time MCPCs, Real-Time Reliability Deployment Price Adders, Hub LMPs and Load Zone LMPs on the ERCOT website pursuant to Section 6.3.2, Activities for Real-Time Operations.  (17) ERCOT may override one or more of a CLR’s parameters in SCED if ERCOT determines that the CLR’s participation is having an adverse impact on the reliability of the ERCOT System.  (18) The QSE representing an ESR may withdraw energy from the ERCOT System only when dispatched by SCED to do so. An ESR may telemeter a status of OUT only if the ESR is in Outage status. |

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| ***[NPRR1290: Replace paragraph (15)(d) above with the following upon system implementation:]***  (d) Any Electrical Bus LMP above the effective VOLL shall be set equal to the greater of the effective VOLL or the initial LMP minus the positive difference between System Lambda and the effective VOLL. All other Electrical Bus LMPs below the effective VOLL remain unchanged. These adjustments shall be applied to Electrical Bus LMPs prior to calculating Real-Time Settlement Point LMPs, Real-Time Settlement Point Prices, and Real-Time prices for energy metered.  The System Lambda from SCED Step 2 shall also be capped at the effective VOLL. ERCOT shall post both the capped and uncapped Electrical Bus LMP and System Lambda values to the ERCOT website. |

**6.5.7.3.1Determination of Real-Time On-Line Reliability Deployment Price Adder**

(1) The following categories of reliability deployments are considered in the determination of the Real-Time On-Line Reliability Deployment Price Adder:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than CLRs;

(d) Deployed ERS;

(e) Real-Time DC Tie imports during an EEA where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) Real-Time DC Tie exports to address emergency conditions in the receiving electric grid;

(g) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;

(h) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid; and

(i) ERCOT-directed firm Load shed during EEA Level 3, as described in paragraph (3) of Section 6.5.9.4.2, EEA Levels.

(2) The Real-Time On-Line Reliability Deployment Price Adder is an estimation of the impact to energy prices due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, after the two-step SCED process and also after the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder have been determined, the Real-Time On-Line Reliability Deployment Price Adder is determined as follows:

(a) For RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line, set the LSL, LASL, and LDL to zero.

(b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity, set the LSL, LASL, and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.

(c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes \* SCED Down Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes\*SCED Up Ramp Rate), or HASL.

(d) For all CLRs excluding ones with a telemetered status of OUTL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes \* SCED Up Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes\*SCED Down Ramp Rate), or HASL.

(e) Add the deployed MW from Load Resources that are not CLRs and that are providing RRS or ECRS to GTBD linearly ramped over the ten-minute ramp period and add the deployed MW from Load Resources that are not CLRs providing Non-Spin to GTBD linearly ramped over the 30-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the restoration period length and amount of MW added to GTBD during the restoration period will be determined by validated telemetry and the type of Ancillary Service deployed from the Resource. The TAC shall review the validity of the prices for the bid curve at least annually.

(f) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period (“RHours”).

The above parameter is defined as follows:

| **Parameter** | **Unit** | **Current Value\*** |
| --- | --- | --- |
| RHours | Hours | 4.5 |
| \* Changes to the current value of the parameter(s) referenced in this table above may be recommended by TAC and the ERCOT Board and approved by the Public Utility Commission of Texas (PUCT). ERCOT shall update parameter values on the first day of the month following PUCT approval unless otherwise directed. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value. | | |

(g) Add the MW from Real-Time DC Tie imports during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(h) Subtract the MW from Real-Time DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(i) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(j) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(k) Perform a SCED with changes to the inputs in items (a) through (j) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.

(l) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.

(m) Perform a SCED with the changes to the inputs in items (a) through (j) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy Offer Curves.

(n) Determine the positive difference between the System Lambda from item (m) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(o) Determine the amount given by the Value of Lost Load (VOLL) minus the sum of the System Lambda of the second step in the two step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder.

(p) The Real-Time On-Line Reliability Deployment Price Adder is the minimum of items (n) and (o) above except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time On-Line Reliability Deployment Price Adder is the VOLL minus the sum of the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder. Once ERCOT is no longer directing firm Load shed, as described above, the Real-Time On-Line Reliability Deployment Price Adder will again be set as the minimum of items (n) and (o) above.

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| ***[NPRR904, NPRR1006, NPRR1010, NPRR1014, NPRR1091, NPRR1105, NPRR1188, NPRR1238, and NPRR1245: Replace applicable portions of Section 6.5.7.3.1 above with the following upon system implementation for NPRR904, NPRR1006, NPRR1014, NPRR1091, NPRR1105, NPRR1188, or NPRR1238; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1245:]***  **6.5.7.3.1Determination of Real-Time Reliability Deployment Price Adder**  (1) The following categories of reliability deployments are considered in the determination of the Real-Time Reliability Deployment Price Adder for Energy, and the Real-Time Reliability Deployment Price Adders for Ancillary Services:  (a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;  (b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority;  (c) Deployed Load Resources other than CLRs;  (d) Deployed ERS;  (e) ERCOT-directed DC Tie imports during an EEA or transmission emergency where the total adjustment shall not exceed 1,250 MW in a single interval;  (f) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;  (g) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT where the total adjustment shall not exceed 1,250 MW in a single interval;  (h) ERCOT-directed DC Tie exports to address emergency conditions in the receiving electric grid where the total adjustment shall not exceed 1,250 MW in a single interval;  (i) ERCOT-directed curtailment of DC Tie exports below the DC Tie advisory export limit as of 0600 in the Day-Ahead or subsequent advisory export limit during EEA, a transmission emergency, or to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;  (j) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;  (k) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid;  (l) ERCOT-directed deployment of TDSP standard offer Load management programs;  (m) ERCOT-directed deployment of distribution voltage reduction measures;  (n) ERCOT-directed deployment of Off-Line Non-Spin;  (o) ERCOT-directed firm Load shed during EEA Level 3, as described in paragraph (3) of Section 6.5.9.4.2, EEA Levels; and  (p) Deployed Voluntary Early Curtailment Load (VECL) as described in Section 6.5.9.4.1, General Procedures Prior to EEA Operations.  (2) The Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Services are estimations of the impact to energy prices and Real-Time MCPCs due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, the Real-Time Reliability Deployment Price Adder for Energy and Real-Time Reliability Deployment Price Adders for Ancillary Services are determined as follows:  (a) For Off-Line Non-Spin Resources that are brought On-Line by ERCOT deployment instruction, RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line:  (i) Set the LSL and LDL to zero;  (ii) Remove all Ancillary Service Offers; and  (iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the power balance penalty price for all capacity between 0 MW and the HSL of the Resource.  (b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity:  (i) Set the LSL and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction;  (ii) Set the maximum Ancillary Service capabilities of the Resource equal to the minimum of their current value and COP Ancillary Service capabilities of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction; and  (iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the power balance penalty price for the additional capacity of the Resource, defined as the positive difference between the Resource’s current telemetered HSL and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.  (c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, ONHOLD, ONSC, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:  (i) If the Generation Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes \* Normal Ramp Rate down), or LSL; and  (ii) If the Generation Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes \* Normal Ramp Rate up), or HSL.  (d) For all On-Line ESRs excluding those with a telemetered status of ONTEST or ONHOLD:  (i) If the ESR SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes \* Normal Ramp Rate down), or LSL; and  (ii) If the ESR SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes \* Normal Ramp Rate up), or HSL.  (e) For all CLRs excluding ones with a telemetered status of OUTL, ONTEST, or ONHOLD:  (i) If the CLR SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes \* Normal Ramp Rate up), or LSL; and  (ii) If the CLR SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes \* Normal Ramp Rate down), or HSL.  (f) Add the deployed MW from Load Resources that are not CLRs and that are providing RRS or ECRS to GTBD linearly ramped over the ten-minute ramp period and add the deployed MW from Load Resources that are not CLRs providing Non-Spin to GTBD linearly ramped over the 30-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the restoration period length and amount of MW added to GTBD during the restoration period will be determined by validated telemetry and the type of Ancillary Service deployed from the Resource. The TAC shall review the validity of the prices for the bid curve at least annually.  (g) Add the deployed MW from VECL to GTBD linearly ramped over a 30-minute ramp period. The amount of deployed MW is calculated from the applicable deployment instructions in XML messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of VECL deployed and a price/quantity pair of $700/MWh for the last MW of VECL deployed in each SCED execution. After recall instruction, GTBD shall be adjusted to reflect restoration on a linear curve over a one-hour restoration period.  (h) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period (“RHours”).  The above parameter is defined as follows:   | **Parameter** | **Unit** | **Current Value\*** | | --- | --- | --- | | RHours | Hours | 4.5 | | \* Changes to the current value of the parameter(s) referenced in this table above may be recommended by TAC and the ERCOT Board and approved by the Public Utility Commission of Texas (PUCT). ERCOT shall update parameter values on the first day of the month following PUCT approval unless otherwise directed. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value. | | |   (i) Add the MW from DC Tie imports during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.  (j) Add the MW from DC Tie export curtailments during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator. The MW added to GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for exports on that tie as of 0600 in the Day-Ahead or subsequent advisory export limit minus the aggregate export on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.  (k) Subtract the MW from DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.  (l) Subtract the MW from DC Tie import curtailments to address local transmission system limitations or emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator. The MW subtracted from GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for imports on that tie as of 0600 in the Day-Ahead or subsequent advisory import limit minus the aggregate import on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.  (m) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.  (n) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.  (o) Add the deployed MWs from TDSP standard offer Load management programs to GTBD, if ERCOT instructs TDSPs to deploy their standard offer Load management programs. The amount of deployed MW is the value ERCOT provided for all TDSP standard offer Load management programs in the most current May Report on Capacity, Demand and Reserves in the ERCOT Region (CDR), unless modified as specified in this paragraph. If ERCOT is informed that all or a portion of a TDSP’s standard offer Load management program has been fully exhausted, or has been expanded as the result of a Public Utility Commission of Texas (PUCT) proceeding, ERCOT will remove the associated MW value of any exhausted capacity from the amount of deployed MW or, in the case of an expansion, ERCOT will request an updated MW value from the relevant TDSPs to use in place of the May CDR in the ERCOT Region value for that year. The initial value ERCOT will use for deployed MW under this paragraph for each calendar year, as well as any subsequent changes to this value, will be communicated to Market Participants in a Market Notice. After recall, an approximation of the amount of un-restored TDSP standard offer Load management programs shall be used. GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period (“RHours”) defined by item (h) above.  (p) Perform a SCED with changes to the inputs in items (a) through (n) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.  (q) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.  (r) Perform a SCED with the changes to the inputs in items (a) through (n) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy Offer Curves.  (s) The Real-Time Reliability Deployment Price Adder for Energy is equal to the positive difference between the System Lambda from item (r) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch, except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time Reliability Deployment Price Adder for Energy is the VOLL used to determine the Ancillary Service Demand Curves (ASDCs) for the Real-Time Market (RTM) minus the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3.  (t) For each individual Ancillary Service, the Real-Time Reliability Deployment Price Adder for Ancillary Service is equal to the positive difference between the MCPC for that Ancillary Service from item (r) above and the MCPC for that Ancillary Service, except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time Reliability Deployment Price Adder for Ancillary Service is the maximum value on the ASDC for the Ancillary Service minus the MCPC for that Ancillary Service. |

**6.5.7.5 Ancillary Services Capacity Monitor**

(1) ERCOT shall calculate the following every ten seconds and provide Real-Time summaries to ERCOT Operators and all Market Participants using ICCP, giving updates of calculations every ten seconds, and posting on the ERCOT website, giving updates of calculations every five minutes, which show the Real-Time total system amount of:

(a) RRS capacity from:

(i) Generation Resources;

(ii) Load Resources excluding CLRs;

(iii) CLRs; and

(iv) Resources capable of Fast Frequency Response (FFR);

(b) Ancillary Service Resource Responsibility for RRS from:

(i) Generation Resources;

(ii) Load Resources excluding CLRs;

(iii) CLRs; and

(iv) Resources capable of FFR;

(c) ECRS capacity from:

(i) Generation Resources;

(ii) Load Resources excluding CLRs;

(iii) CLRs; and

(iv) Quick Start Generation Resources (QSGRs);

(d) Ancillary Service Resource Responsibility for ECRS from:

(i) Generation Resources;

(ii) Load Resources excluding CLRs; and

(iii) CLRs; and

(iv) QSGRs;

(e) ECRS deployed to Generation and Load Resources;

(f) Non-Spin available from:

(i) On-Line Generation Resources with Energy Offer Curves;

(ii) Undeployed Load Resources;

(iii) Off-Line Generation Resources; and

(iv) Resources with Output Schedules;

(g) Ancillary Service Resource Responsibility for Non-Spin from:

(i) On-Line Generation Resources with Energy Offer Curves;

(ii) On-Line Generation Resources with Output Schedules;

(iii) Load Resources;

(iv) Off-Line Generation Resources excluding QSGRs; and

(v) QSGRs;

(h) Undeployed Reg-Up and Reg-Down;

(i) Ancillary Service Resource Responsibility for Reg-Up and Reg-Down;

(j) Deployed Reg-Up and Reg-Down;

(k) Available capacity:

(i) With Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;

(ii) With Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;

(iii) Without Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;

(iv) Without Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;

(v) With RTM Energy Bid curves from available CLRs in the ERCOT System that can be used to decrease Base Points (energy consumption) in SCED;

(vi) With RTM Energy Bid curves from available CLRs in the ERCOT System that can be used to increase Base Points (energy consumption) in SCED;

(vii) From Resources participating in SCED plus the Reg-Up, ECRS, and RRS from Load Resources and the Net Power Consumption minus the Low Power Consumption from Load Resources with a validated Real-Time RRS and ECRS Schedule;

(viii) From Resources included in item (vii) above plus reserves from Resources that could be made available to SCED in 30 minutes;

(ix) In the ERCOT System that can be used to increase Generation Resource Base Points in the next five minutes in SCED; and

(x) In the ERCOT System that can be used to decrease Generation Resource Base Points in the next five minutes in SCED;

(l) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of EMR;

(m) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of OUT;

(n) Aggregate net telemetered consumption for Resources with a telemetered Resource Status of OUTL; and

(o) The ERCOT-wide PRC calculated as follows:

**PRC1 = Min(Max((RDF\*(HSL-NFRC) – Actual Net Telemetered Output)i , 0.0) , 0.2\*RDF\*(HSL-NFRC)i),**

where the included On-Line Generation Resources do not include WGRs, nuclear Generation

Resources, or Generation Resources with an output less than or equal to 95% of telemetered LSL or

with a telemetered status of ONTEST, ONHOLD, STARTUP, or SHUTDOWN.

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***WGRs***

***online***

***All***

***WGR***

***online***

***i***

**PRC2 = Min(Max((RDFW\*HSL – Actual Net Telemetered Output)i , 0.0) , 0.2\*RDFW\*HSLi),**

where the included On-Line WGRs only include WGRs that are Primary Frequency Response-capable.

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**PRC3 = ((Synchronous condenser output)i as qualified by item (8) of Operating Guide Section 2.3.1.2, Additional Operational Details for Responsive Reserve and ERCOT Contingency Reserve Service Providers))**

**PRC4 = (Min(Max((Actual Net Telemetered Consumption – LPC), 0.0), ECRS and RRS Ancillary Service Resource Responsibility \* 1.5) from all Load Resources controlled by high-set under frequency relays carrying an ECRS and/or RRS Ancillary Service Resource Responsibility)i**

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***resources***

***load***

***online***

***All***

***resource***

***load***

***online***

***i***

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***resources***

***load***

***online***

***All***

***resource***

***load***

***online***

***i***

**PRC5 = Min(Max((LRDF\_1\*Actual Net Telemetered Consumption – LPC)i, 0.0), (0.2 \* LRDF\_1 \* Actual Net Telemetered Consumption)) from all CLRs active in SCED and carrying Ancillary Service Resource Responsibility**

**PRC6 = Min(Max((LRDF\_2 \* Actual Net Telemetered Consumption – LPC)i, 0.0), (0.2 \* LRDF\_2 \* Actual Net Telemetered Consumption)) from all CLRs active in SCED and not carrying Ancillary Service Resource Responsibility**

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***resources***

***load***

***online***

***All***

***resource***

***load***

***online***

***i***

**PRC7 = (Capacity from Resources capable of providing FFR)i**

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***resources***

***FFR***

***online***

***All***

***resource***

***FFR***

***online***

***i***

**PRC8 = (If discharging or idle, Min(X% of HSL based on droop, HSL-ESR-Gen “injection”, the capacity that can be sustained for 45 minutes per the State of Charge), else Min(X% of (HSL – LSL(ESR “charging”) based on droop, the capacity that can be sustained for 45 minutes per the State of Charge – LSL(ESR “charging”)))**

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***ESR***

***online***

***All***

***ESR***

***online***

***i***

**Excludes ESR capacity used to provide FFR.**

**PRC = PRC1 + PRC2 + PRC3 + PRC4 + PRC5 + PRC6 + PRC7 + PRC8**

The above variables are defined as follows:

|  |  |  |
| --- | --- | --- |
| **Variable** | **Unit** | **Description** |
| PRC1 | MW | Generation On-Line greater than 0 MW |
| PRC2 | MW | WGRs On-Line greater than 0 MW |
| PRC3 | MW | Synchronous condenser output |
| PRC4 | MW | Capacity from Load Resources carrying ECRS Ancillary Service Resource Responsibility |
| PRC5 | MW | Capacity from CLRs active in SCED and carrying Ancillary Service Resource Responsibility |
| PRC6 | MW | Capacity from CLRs active in SCED and not carrying Ancillary Service Resource Responsibility |
| PRC7 | MW | Capacity from Resources capable of providing FFR |
| PRC8 | MW | ESR capacity capable of providing Primary Frequency Response |
| PRC | MW | Physical Responsive Capability |
| X | Percentage | Percent threshold based on the Governor droop setting of ESRs |
| RDF |  | The currently approved Reserve Discount Factor |
| RDFW |  | The currently approved Reserve Discount Factor for WGRs |
| LRDF\_1 |  | The currently approved Load Resource Reserve Discount Factor for CLRs carrying Ancillary Service Resource Responsibility |
| LRDF\_2 |  | The currently approved Load Resource Reserve Discount Factor for CLRs not carrying Ancillary Service Resource Responsibility |
| NFRC | MW | Non-Frequency Responsive Capacity |

(2) Each QSE shall operate Resources providing Ancillary Service capacity to meet its obligations. If a QSE experiences temporary conditions where its total obligation for providing Ancillary Service cannot be met on the QSE’s Resources, then the QSE may add additional capability from other Resources that it represents. It adds that capability by changing the Resource Status and updating the Ancillary Service Schedules and Ancillary Services Resource Responsibility of the affected Resources and notifying ERCOT under Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency. If the QSE is unable to meet its total obligations to provide committed Ancillary Services capacity, the QSE shall notify ERCOT immediately of the expected duration of the QSE’s inability to meet its obligations. ERCOT shall determine whether replacement Ancillary Services will be procured to account for the QSE’s shortfall according to Section 6.4.9.1.

(3) The Load Resource Reserve Discount Factors (RDFs) for CLRs (LRDF\_1 and LRDF\_2) shall be subject to review and approval by TAC.

(4) The RDFs used in the PRC calculation shall be posted to the ERCOT website no later than three Business Days after approval.

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| * ***[NPRR1010, NPRR1014, NPRR1029, NPRR1188, NPRR1204, and NPRR1244: Replace applicable portions of Section 6.5.7.5 above with the following upon system implementation for NPRR1014, NPRR1029, NPRR1188, or NPRR1224; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1204:]***   **6.5.7.5 Ancillary Services Capacity Monitor**  (1) Every ten seconds, ERCOT shall calculate the following and provide Real-Time summaries to ERCOT Operators and all Market Participants using ICCP and postings on the ERCOT website showing the Real-Time total system amount of:  (a) RRS capability from:  (i) Generation Resources and ESRs in the form of PFR that can be sustained for the SCED duration requirements of PFR;  (ii) Load Resources, excluding CLRs, capable of responding via under-frequency relay;  (iii) CLRs in the form of PFR;  (iv) Resources, other than ESRs, capable of Fast Frequency Response (FFR); and  (v) ESRs, in the form of FFR, that can be sustained for the SCED duration requirements of FFR;  (b) Ancillary Service Resource awards for RRS to:  (i) Generation Resources and ESRs in the form of PFR;  (ii) Load Resources, excluding CLRs, capable of responding by under-frequency relay;  (iii) CLRs in the form of PFR; and  (iv) Resources providing FFR;  (c) ECRS capability from:  (i) Generation Resources;  (ii) Load Resources excluding CLRs;  (iii) CLRs;  (iv) Quick Start Generation Resources (QSGRs); and  (v) ESRs that can be sustained for the SCED duration requirements of ECRS.  (d) Ancillary Service Resource awards for ECRS to:  (i) Generation Resources;  (ii) Load Resources excluding CLRs; and  (iii) CLRs;  (iv) QSGRs; and  (v) ESRs.  (e) ECRS manually deployed by Resources with a Resource Status of ONSC;  (f) Non-Spin available from:  (i) On-Line Generation Resources with Energy Offer Curves;  (ii) Undeployed Load Resources;  (iii) Off-Line Generation Resources and On-Line Generation Resources with power augmentation;  (iv) Resources with Output Schedules; and  (v) ESRs that can be sustained for the SCED duration requirements of Non-Spin.  (g) Ancillary Service Resource awards for Non-Spin to:  (i) On-Line Generation Resources with Energy Offer Curves;  (ii) On-Line Generation Resources with Output Schedules;  (iii) Load Resources;  (iv) Off-Line Generation Resources excluding Quick Start Generation Resources (QSGRs), including Non-Spin awards on power augmentation capacity that is not active on On-Line Generation Resources;  (v) QSGRs; and  (vi) ESRs.  (h) Reg-Up and Reg-Down capability (for ESRs, the SCED duration requirements of Reg-Up and Reg-Down are considered);  (i) Undeployed Reg-Up and Reg-Down;  (j) Ancillary Service Resource awards for Reg-Up and Reg-Down;  (k) Deployed Reg-Up and Reg-Down;  (l) Available capacity:  (i) With Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;  (ii) With Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;  (iii) Without Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;  (iv) Without Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;  (v) With Energy Bid Curves from available CLRs in the ERCOT System that can be used to decrease Base Points (energy consumption) in SCED;  (vi) With Energy Bid Curves from available CLRs in the ERCOT System that can be used to increase Base Points (energy consumption) in SCED;  (vii) From Resources participating in SCED plus the Reg-Up, RRS, and ECRS from Load Resources and the Net Power Consumption minus the Low Power Consumption from Load Resources with a validated Real-Time RRS and ECRS awards;  (viii) With Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to increase ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;  (ix) With Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to decrease ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;  (x) Without Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to increase ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;  (xi) Without Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to decrease ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;  (xii) From Resources included in item (vii) above plus reserves from Resources that could be made available to SCED in 30 minutes;  (xiii) In the ERCOT System that can be used to increase Generation Resource Base Points in the next five minutes in SCED; and  (xiv) In the ERCOT System that can be used to decrease Generation Resource Base Points in the next five minutes in SCED;  (xv) The total capability of Resources available to provide the following combinations of Ancillary Services, based on the Resource telemetry from the QSE and capped by the limits of the Resource:  (A) Capacity to provide Reg-Up, RRS, or both, irrespective of whether it is capable of providing ECRS or Non-Spin;  (B) Capacity to provide Reg-Up, RRS, ECRS, or any combination, irrespective of whether it is capable of providing Non-Spin; and  (C) Capacity to provide Reg-Up, RRS, ECRS, or Non-Spin, in any combination;  (m) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of EMR;  (n) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of OUT;  (o) Aggregate net telemetered consumption for Resources with a telemetered Resource Status of OUTL; and  (p) The ERCOT-wide PRC calculated as follows:  **PRC1 = Min(Max((RDF\*FRCHL – FRCO)i , 0.0) , 0.2\*RDF\*FRCHLi),**  where the included On-Line Generation Resources do not include WGRs, nuclear Generation  Resources, or Generation Resources with an output less than or equal to 95% of telemetered LSL or  with a telemetered status of ONTEST, ONHOLD, STARTUP, or SHUTDOWN.      ***WGRs***  ***online***  ***All***  ***WGR***  ***online***  ***i***  **PRC2 = Min(Max((RDFW\*HSL – Actual Net Telemetered Output)i , 0.0) , 0.2\*RDFW\*HSLi),**  where the included On-Line WGRs only include WGRs that are Primary Frequency Response-capable.  **PRC3 = ((Synchronous condenser output)i as qualified by item (8) of Operating Guide Section 2.3.1.2, Additional Operational Details for Responsive Reserve and ERCOT Contingency Reserve Service Providers))**  **PRC4 = (Min(Max((Actual Net Telemetered Consumption – LPC), 0.0), ECRS and RRS Ancillary Service Resource award \* 1.5) from all Load Resources controlled by high-set under-frequency relays with an ECRS and/or RRS Ancillary Service Resource award)i**      ***resources***  ***load***  ***online***  ***All***  ***resource***  ***load***  ***online***  ***i***  **PRC5 = Min(Max((LRDF\_1\*Actual Net Telemetered Consumption – LPC)i, 0.0), (0.2 \* LRDF\_1 \* Actual Net Telemetered Consumption)) from all CLRs active in SCED and qualified for Regulation Service and/or RRS with an Ancillary Service Resource award**      ***resources***  ***load***  ***online***  ***All***  ***resource***  ***load***  ***online***  ***i***  **PRC6 = Min(Max((LRDF\_2 \* Actual Net Telemetered Consumption – LPC)i, 0.0), (0.2 \* LRDF\_2 \* Actual Net Telemetered Consumption)) from all CLRs active in SCED and qualified for Regulation Service and/or RRS without an Ancillary Service Resource award**      ***resources***  ***load***  ***online***  ***All***  ***resource***  ***load***  ***online***  ***i***  **PRC7 = (Capacity from Resources capable of providing FFR)i**      ***resources***  ***FFR***  ***online***  ***All***  ***resource***  ***FFR***  ***online***  ***i***  **PRC8 = Min(X% of MDRR, HSL-Net MW, the capacity that can be sustained for 45 minutes per the State of Charge**      ***ESR***  ***online***  ***All***  ***ESR***  ***online***  ***i***  **Excludes ESR capacity used to provide FFR.**  **PRC9 = Min(X% of MDRR, HSL-Net MW, the sum of the MW headroom available from the intermittent renewable generation component and the MW capacity that can be sustained for 45 minutes per the ESS State of Charge)**      ***DC-Coupled Resources***  ***online***  ***All***  ***ESR***  ***online***  ***i***  **Excludes DC-Coupled Resource capacity used to provide FFR.**  **PRC = PRC1 + PRC2 + PRC3+ PRC4 + PRC5 + PRC6 + PRC7 + PRC8 + PRC9**  The above variables are defined as follows:   |  |  |  | | --- | --- | --- | | **Variable** | **Unit** | **Description** | | PRC1 | MW | Generation On-Line greater than 0 MW | | PRC2 | MW | WGRs On-Line greater than 0 MW | | PRC3 | MW | Synchronous condenser output | | PRC4 | MW | Capacity from Load Resources with an ECRS Ancillary Service Resource award | | PRC5 | MW | Capacity from CLRs active in SCED and qualified for Regulation Service and/or RRS with an Ancillary Service Resource award | | PRC6 | MW | Capacity from CLRs active in SCED and qualified for Regulation Service and/or RRS without an Ancillary Service Resource award | | PRC7 | MW | Capacity from Resources capable of providing FFR | | PRC8 | MW | ESR capacity capable of providing Primary Frequency Response | | PRC9 | MW | Capacity from DC-Coupled Resources capable of providing Primary Frequency Response | | PRC | MW | Physical Responsive Capability | | X | Percentage | Percent threshold based on the Governor droop setting of ESRs | | RDF |  | The currently approved Reserve Discount Factor | | RDFW |  | The currently approved Reserve Discount Factor for WGRs | | LRDF\_1 |  | The currently approved Load Resource Reserve Discount Factor for CLRs awarded an Ancillary Service Resource award | | LRDF\_2 |  | The currently approved Load Resource Reserve Discount Factor for CLRs not awarded an Ancillary Service Resource award | | FRCHL | MW | Telemetered High limit of the FRC for the Resource | | FRCO | MW | Telemetered output of FRC portion of the Resource |   (2) The Load Resource Reserve Discount Factors (RDFs) for CLRs (LRDF\_1 and LRDF\_2) shall be subject to review and approval by TAC.  (3) The RDFs used in the PRC calculation shall be posted to the ERCOT website no later than three Business Days after approval.  (4) ERCOT shall display on the ERCOT website and update every ten seconds a rolling view of the ERCOT-wide PRC, as defined in paragraph (1)(p) above, for the current Operating Day. |

**6.6.3.1 Real-Time Energy Imbalance Payment or Charge at a Resource Node**

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

(a) The energy produced by all its Generation Resources, consumed as WSL, or consumed as Non-WSL ESR Charging Load at the Settlement Point; plus

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| ***[NPRR1188: Replace item (a) above with the following upon system implementation:]***  (a) The energy produced or consumed at the Settlement Point by all its Generation Resources, ESR Charging Load with WSL treatment, ESR Charging Load with Non-WSL treatment, or CLRs that are not ALRs; plus |

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

(c) The amount of its Day-Ahead Market (DAM) Energy Bids cleared in the DAM at the Settlement Point; plus

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

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

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

(g) The amount of its Energy Trades at the Settlement Point where the QSE is the seller.

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

**RTEIAMT *q, p* = (-1) \* {((RESREV *q, r, gsc, p*)) + (WSLAMTTOT *q, r, p*) + (ESRNWSLAMTTOT *q, r, p*) + RTSPP *p* \* [(SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼)]}**

Where:

RESREV *q, r, gsc, p* = GSPLITPER *q, r, gsc, p* \* NMSAMTTOT *gsc*

RESMEB *q, r, gsc, p* = GSPLITPER *q, r, gsc, p* \* NMRTETOT *gsc*

WSLTOT *q, p* =  ( MEBL *q, r, b*)

ESRNWSLTOT *q, p* =  ( MEBR *q, r, b*)

RNIMBAL *q, p =* (RESMEB *q, r, gsc, p*) + WSLTOT *q, p* + ESRNWSLTOT *q, p* + (SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼)

The above variables are defined as follows:

| **Variable** | **Unit** | **Description** |
| --- | --- | --- |
| RTEIAMT *q, p* | $ | *Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval. |
| RNIMBAL *q, p* | MWh | *Resource Node Energy Imbalance per QSE per Settlement Point*—The Resource Node volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval. |
| RTSPP *p* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval. |
| SSSK *q, p* | MW | *Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*’s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval. |
| DAEP *q, p* | MW | *Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*’s DAM Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval. |
| RTQQEP *q, p* | MW | *Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*¾The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval. |
| SSSR *q, p* | MW | *Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*’s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval. |
| DAES *q, p* | MW | *Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*’s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval. |
| RTQQES *q, p* | MW | *Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*¾The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval. |
| RESREV *q, r, gsc, p* | $ | *Resource Share Revenue Settlement Payment*—The Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. |
| RESMEB *q, r, gsc, p* | MWh | *Resource Share Net Meter Real-Time Energy Total*—The Resource share of the net sum for all Settlement Meters attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. |
| WSLTOT *q, p* | MWh | *WSL Total*—The total WSL energy metered by the Settlement Meters which measure WSL for the QSE *q* at Settlement Point *p*. |
| ESRNWSLTOT *q, p* | MWh | *ESR Non-WSL Total*—The total energy metered by the Settlement Meters which measures Non-WSL ESR Charging Load for the QSE *q* at Settlement Point *p.* |
| MEBL *q,r,b* | MWh | *Metered Energy for Wholesale Storage Load at bus*¾The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. |
| MEBR *q, r, b* | MWh | *Metered Energy for Energy Storage Resource Load at Bus*—The energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. |
| NMSAMTTOT *gsc* | $ | *Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement. |
| WSLAMTTOT*q, r, p* | $ | *Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval. |
| ESRNWSLAMTTOT*q, r, p* | $ | *Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval. |
| NMRTETOT *gsc* | MWh | *Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System. |
| GSPLITPER *q, r, gsc, p* | none | *Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a net metering arrangement. GSPLITPER is calculated by taking the Supervisory Control and Data Acquisition (SCADA) values (GSSPLITSCA) for a particular Generation Resource *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| *q* | none | A QSE. |
| *p* | none | A Resource Node Settlement Point. |
| *r* | none | A Generation Resource or a Controllable Load Resource (CLR) that is part of an ESR that is located at the Facility with net metering. |
| *gsc* | none | A generation site code. |
| *b* | none | An Electrical Bus. |

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| ***[NPRR1014 and NPRR1188: Replace applicable portions of paragraph (2) above with the following upon system implementation:]***  (2) The payment or charge to each QSE for Energy Imbalance Service at a Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:  **RTEIAMT *q, p* = (-1) \* {((RESREV *q, r, gsc, p*)) + (WSLAMTTOT *q, r, p*) + (CLRAMTTOT *q, r, p*) + (ESRNWSLAMTTOT *q, r, p*) + RTSPP *p* \* [(SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼)]}**  Where:  RESREV *q, r, gsc, p* = GSPLITPER *q, r, gsc, p* \* NMSAMTTOT *gsc*  RESMEB *q, r, gsc, p* = GSPLITPER *q, r, gsc, p* \* NMRTETOT *gsc*  WSLTOT *q, p* =  ( MEBL *q,r,b*)  CLRTOT *q, p* = (MEBCL *q, r, b*)  ESRNWSLTOT *q, p* =  ( MEBR *q, r, b*)  RNIMBAL *q, p =* (RESMEB *q, r, gsc, p*) + WSLTOT *q, p* + CLRTOT *q, p* + ESRNWSLTOT *q, p* + (SSSK *q, p* \* ¼) + (DAEP *q, p* \* ¼) + (RTQQEP *q, p* \* ¼) – (SSSR *q, p* \* ¼) – (DAES *q, p* \* ¼) – (RTQQES *q, p* \* ¼)  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTEIAMT *q, p* | $ | *Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval. | | RNIMBAL *q, p* | MWh | *Resource Node Energy Imbalance per QSE per Settlement Point*—The Resource Node volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval. | | RTSPP *p* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval. | | SSSK *q, p* | MW | *Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*’s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval. | | DAEP *q, p* | MW | *Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*’s DAM Energy Bids, Energy Bid Curves, and bid portion of Energy Bid/Offer Curves at Settlement Point *p*, cleared in the DAM, for the hour that includes the 15-minute Settlement Interval. | | RTQQEP *q, p* | MW | *Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*¾The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval. | | SSSR *q, p* | MW | *Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*’s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval. | | DAES *q, p* | MW | *Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*’s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval. | | RTQQES *q, p* | MW | *Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*¾The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval. | | RESREV *q, r, gsc, p* | $ | *Resource Share Revenue Settlement Payment*—The Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. | | RESMEB *q, r, gsc, p* | MWh | *Resource Share Net Meter Real-Time Energy Total*—The Resource share of the net sum for all Settlement Meters attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. | | WSLTOT *q, p* | MWh | *WSL Total*—The total WSL energy metered by the Settlement Meters which measure WSL for the QSE *q* at Settlement Point *p*. | |  | | | | CLRTOT *q, p* | MWh | *CLR Load Total*—The total energy metered by the Settlement Meters which measures CLR Load for the QSE *q* at Settlement Point *p.* | | ESRNWSLTOT *q, p* | MWh | *ESR Non-WSL Total*—The total energy metered by the Settlement Meters which measure Non-WSL ESR Charging Load for the QSE *q* at Settlement Point *p.* | | MEBL *q,r,b* | MWh | *Metered Energy for Wholesale Storage Load at bus*¾The 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*. | |  | | | | MEBCL *q, r, b* | MWh | *Calculated Metered Energy for CLR Load at Bus*—The calculated CLR Load, adjusted for Unaccounted For Energy (UFE), 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 | *Calculated Metered Energy for Energy Storage Resource Load at Bus -* The calculated Non-WSL ESR Charging Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | NMSAMTTOT *gsc* | $ | *Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement. | | CLRAMTTOT*q, r, p* | $ | *CLR Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for CLR Load for each 15-minute Settlement Interval. | | WSLAMTTOT*q, r, p* | $ | *Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval. | | ESRNWSLAMTTOT*q, r, p* | $ | *Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval. | | NMRTETOT *gsc* | MWh | *Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System. | | GSPLITPER *q, r, gsc, p* | none | *Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a net metering arrangement. GSPLITPER is calculated by taking the positive Supervisory Control and Data Acquisition (SCADA) values (GSSPLITSCA) for a particular Generation Resource or ESR *r* that is part of a net metering configuration and dividing by the sum of all positive SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | *q* | none | A QSE. | | *p* | none | A Resource Node Settlement Point. | | *r* | none | A Generation Resource, a CLR that is not an ALR, or ESR that is located at the Facility with net metering. | | *gsc* | none | A generation site code. | | *b* | none | An Electrical Bus. | |

(3) For a facility with Settlement Meters that measure ESR Load, the total payment or charge for ESR Load is calculated for a QSE, ESR, and Settlement Point for each 15-minute Settlement Interval.

The WSL is settled as follows:

**WSLAMTTOT *q, r, p* =**  **(RTRMPRESR *b* \* MEBL** ***q, r, b*)**

The Non-WSL ESR Charging Load is settled as follows:

**ESRNWSLAMTTOT *q, r, p* =**  **(RTRMPRESR *b* \* MEBR** ***q, r, b*)**

Where the price for Settlement Meter is determined as follows:

**RTRMPRESR *b* = Max [-$251, (image010(RNWFL *b, y* \* RTLMP *b, y*) + RTRSVPOR + RTRDP)]**

Where the weighting factor for the Electrical Bus associated with the meter is:

**RNWFL *b, y* = [Max (0.001,** image001**BP *r, y*) \* TLMP *y*] /**

**[image010Max (0.001,** image001 **BP *r, y*) \* TLMP *y*]**

Where:

RTRSVPOR = image010(RNWF  *y* \* RTORPA *y*)

RTRDP = (RNWF  *y* \* RTORDPA *y*)

RNWF *y* = TLMP *y* / TLMP *y*

The summation is over all ESR Load *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.

The above variables are defined as follows:

| **Variable** | **Unit** | **Description** |
| --- | --- | --- |
| RTLMP *b, y* | $/MWh | *Real-Time Locational Marginal Price at bus per interval*¾The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*. |
| TLMP *y* | second | *Duration of SCED interval per interval*¾The duration of the SCED interval *y*. |
| RTRSVPOR | $/MWh | *Real-Time Reserve Price for On-Line Reserves*¾The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval. |
| RTORPA*y* | $/MWh | *Real-Time On-Line Reserve Price Adder per interval*¾The Real-Time On-Line Reserve Price Adder for the SCED interval *y*. |
| RTRDP | $/MWh | *Real-Time On-Line Reliability Deployment Price* ¾The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder. |
| RTORDPA*y* | $/MWh | *Real-Time On-Line Reliability Deployment Price Adder* ¾The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*. |
| RNWF *y* | none | *Resource Node Weighting Factor per interval*¾The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. |
| MEBL*q,r,b* | MWh | *Metered Energy for Wholesale Storage Load at bus*¾The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. |
| MEBR *q, r, b* | MWh | *Metered Energy for Energy Storage Resource Load at Bus* - The energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. |
| WSLAMTTOT*q, r, p* | $ | *Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval. |
| ESRNWSLAMTTOT*q, r, p* | $ | *Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval. |
| RNWFL*b, y* | none | *Net meter Weighting Factor per interval for the Energy Metered as Energy Storage Resource Load* ¾The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*, for the ESR Load associated with an ESR. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters. |
| RTRMPRESR*b* | $/MWh | *Real-Time Price for the Energy Metered as Energy Storage Resource Load at bus*¾The Real-Time price for the Settlement Meter which measures ESR Load at Electrical Bus *b*, for the 15-minute Settlement Interval. |
| BP *r, y* | MW | *Base Point per Resource per interval* - The Base Point of Resource *r*, for the SCED interval *y*. |
| *q* | none | A QSE. |
| *gsc* | none | A generation site code. |
| *r* | none | The CLR that is part of an ESR. |
| *p* | none | A Resource Node Settlement Point. |
| *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. |
| *b* | none | An Electrical Bus. |

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| ***[NPRR1010, NPRR1014, and NPRR1188: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1188:]***  (3) For a facility with Settlement Meters that measure CLR (that is not an ALR) or ESR Load, the total payment or charge for CLR (that is not an ALR) or ESR Load is calculated for a QSE, CLR (that is not an ALR) or ESR, and Settlement Point for each 15-minute Settlement Interval.  The WSL is settled as follows:  **WSLAMTTOT *q, r, p* =**  **(RTRMPRESR *b* \* MEBL** ***q, r, b*)**  The Non-WSL ESR Charging Load is settled as follows:  **ESRNWSLAMTTOT *q, r, p* =**  **(RTRMPRESR *b* \* MEBR** ***q, r, b*)**  **Where:**  MEBR*q, r, b* = MEBRFG*q, r, b* + MEBRSG*q, r, b*  The total Non-WSL ESR Charging Load is included in the Real-Time Adjusted Meter Load (AML) per QSE.  Where the price for Settlement Meter is determined as follows:  **RTRMPRESR *b* = Max [-$251, (image010(RNWFL *b, y* \* RTLMP *b, y*) + RTRDP)]**  The CLR Load is settled as follows:  **CLRAMTTOT *q, r, p* =**  **(RTRMPRCLR *b* \* MEBCL** ***q, r, b*)**  **Where:**  MEBCL*q, r, b* = MEBCLFG*q, r, b* + MEBCLSG*q, r, b*  The total CLR Load is included in the Real-Time AML per QSE.  Where the price for Settlement Meter is determined as follows:  **RTRMPRCLR *b* = Max [-$251, (image010(RNWFL *b, y* \* RTLMP *b, y*) + RTRDP)]**  Where the weighting factor for the Electrical Bus associated with the meter is:  **RNWFL *b, y* = [Max (0.001, ABS(** image001**Min(0, BP *r, y*))) \* TLMP *y*] /**  **[image010Max (0.001, ABS(** image001 **Min(0, BP *r, y*))) \* TLMP *y*]**  Where:  RTRDP = (RNWF  *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The summation is over all CLR (that is not an ALR) or ESR Load *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTLMP *b, y* | $/MWh | *Real-Time Locational Marginal Price at bus per interval*¾The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*. | | TLMP *y* | second | *Duration of SCED interval per interval*¾The duration of the SCED interval *y*. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy* ¾The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA*y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy* ¾The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*¾The weight used in the Real-Time Reliability Deployment price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | MEBL*q,r,b* | MWh | *Metered Energy for Wholesale Storage Load at Bus*¾The 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*. | | MEBCL *q, r, b* | MWh | *Calculated Metered Energy for CLR Load at Bus* - The calculated CLR Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | MEBCLFG *q, r, b* | MWh | *Adjusted Metered Energy for CLR Load supplied from the grid at Bus (Calculated)*—The portion of energy metered by the Settlement Meter which measures CLR Load supplied from the grid that is adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | MEBCLSG *q, r, b* | MWh | *Metered Energy for CLR Load supplied from co-located generation with Net Metering arrangement, at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures CLR Load supplied from the co-located generation with Net Metering arrangement. This is not adjusted for losses, 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 | *Calculated Metered Energy for Energy Storage Resource Load at Bus* - The calculated Non-WSL ESR Charging Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | MEBRFG *q, r, b* | MWh | *Adjusted Metered Energy for Energy Storage Resource Load supplied from the grid at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load supplied from the grid that is adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | MEBRSG *q, r, b* | MWh | *Metered Energy for Energy Storage Resource Load supplied from co-located generation with Net Metering arrangement, at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load supplied from the co-located generation with Net Metering arrangement. This is not adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*. | | WSLAMTTOT*q, r, p* | $ | *Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval. | | CLRAMTTOT*q, r, p* | $ | *CLR Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for CLR Load for each 15-minute Settlement Interval. | | ESRNWSLAMTTOT*q, r, p* | $ | *Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval. | | RNWFL*b, y* | none | *Net meter Weighting Factor per interval for the Energy Metered as Energy Storage Resource Load or CLR Load* ¾The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*, for the ESR Load associated with an ESR or for the CLR Load associated with a CLR that is not an ALR. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters. | | RTRMPRESR*b* | $/MWh | *Real-Time Price for the Energy Metered as Energy Storage Resource Load at bus*¾The Real-Time price for the Settlement Meter which measures ESR Load at Electrical Bus *b*, for the 15-minute Settlement Interval. | | RTRMPRCLR*b* | $/MWh | *Real-Time Price for the CLR Energy Metered at bus*¾The Real-Time price for the Settlement Meter which measures CLR Load at Electrical Bus *b*, for the 15-minute Settlement Interval. | | BP *r, y* | MW | *Base Point per Resource per interval* - The Base Point of Resource *r*, for the SCED interval *y*. | | *q* | none | A QSE. | | *gsc* | none | A generation site code. | | *r* | none | A CLR (that is not an ALR) or an ESR. | | *p* | none | A Resource Node Settlement Point. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | | *b* | none | An Electrical Bus. | |

(4) The total payment or charge to a Facility with a net metering arrangement for each 15-minute Settlement Interval shall be calculated as follows:

**NMRTETOT *gsc* = Max (0, ( (MEB *gsc, b +* MEBC *gsc, b*)))**

If NMRTETOT *gsc* = 0 for a 15-minute Settlement Interval, then

The Load that is not WSL is included in the Real-Time AML per QSE.

Otherwise, when NMRTETOT *gsc* **>** 0 for a 15-minute Settlement Interval, then

**NMSAMTTOT** *gsc* **=  [(RTRMPR *b* \* MEB *gsc, b*) + (RTRMPR *b* \* MEBC *gsc, b*)]**

Where the price for Settlement Meter is determined as follows**:**

**RTRMPR *b*** = **Max [-$251, (image010(RNWF *b, y* \* RTLMP *b, y*) + RTRSVPOR + RTRDP)]**

Where the weighting factor for the Electrical Bus associated with the meter is:

**RNWF *b, y* = [Max (0.001,** **BP *r, y*) \* TLMP *y*] /**

**[image010Max (0.001,** **BP *r, y*) \* TLMP *y*]**

Where:

RTRSVPOR = image010(RNWF  *y* \* RTORPA *y*)

RTRDP = (RNWF  *y* \* RTORDPA *y*)

RNWF *y* = TLMP *y* / TLMP *y*

The summation is over all Resources *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.

The above variables are defined as follows:

| **Variable** | **Unit** | **Description** |
| --- | --- | --- |
| NMRTETOT *gsc* | MWh | *Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System. |
| NMSAMTTOT*gsc* | $ | *Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement. |
| RTRMPR *b* | $/MWh | *Real-Time Price for the Energy Metered for each Resource meter at bus*¾The Real-Time price for the Settlement Meter at Electrical Bus *b*, for the 15-minute Settlement Interval. |
| MEB *gsc, b* | MWh | *Metered Energy at bus*¾ The metered energy by the Settlement Meter which is not upstream from another Settlement Meter which measures ESR Load for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy withdrawn. |
| RTRSVPOR | $/MWh | *Real-Time Reserve Price for On-Line Reserves*¾The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval. |
| RTORPA*y* | $/MWh | *Real-Time On-Line Reserve Price Adder per interval*¾The Real-Time On-Line Reserve Price Adder for the SCED interval *y*. |
| RTRDP | $/MWh | *Real-Time On-Line Reliability Deployment Price* ¾The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder. |
| RTORDPA*y* | $/MWh | *Real-Time On-Line Reliability Deployment Price Adder* ¾The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*. |
| RNWF *y* | none | *Resource Node Weighting Factor per interval*¾The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. |
| RTLMP *b, y* | $/MWh | *Real-Time Locational Marginal Price at bus per interval*¾The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*. |
| TLMP *y* | second | *Duration of SCED interval per interval*¾The duration of the SCED interval *y*. |
| RNWF *b, y* | none | *Net meter Weighting Factor per interval*¾The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters. |
| BP *r, y* | MW | *Base Point per Resource per interval*¾The Base Point of Resource *r,* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. |
| MEBC*gsc, b* | MWh | *Metered Energy at bus (Calculated)*¾ The calculated energy for the 15-minute Settlement Interval for a Settlement Meter which is upstream from another Settlement Meter which measures ESR Load. A positive value represents energy produced, and a negative value represents energy withdrawn. |
| *gsc* | none | A generation site code. |
| *r* | none | A Generation Resource that is located at the Facility with net metering. |
| *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. |
| *b* | none | An Electrical Bus. |

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| ***[NPRR1010, NPRR1014, and NPRR1188: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1188:]***  (4) The total payment or charge to a Facility with a net metering arrangement for each 15-minute Settlement Interval shall be calculated as follows:  **NMRTETOT *gsc* = Max (0, ( (MEB *gsc, b +* MEBC *gsc, b*)))**  If NMRTETOT *gsc* = 0 for a 15-minute Settlement Interval, then  The Load that is not WSL is included in the Real-Time AML per QSE.  Otherwise, when NMRTETOT *gsc* **>** 0 for a 15-minute Settlement Interval, then  **NMSAMTTOT** *gsc* **=  [(RTRMPR *b* \* MEB *gsc, b*) + (RTRMPR *b* \* MEBC *gsc, b*)]**  Where the price for Settlement Meter is determined as follows**:**  **RTRMPR *b*** = **Max [-$251, (image010(RNWF *b, y* \* RTLMP *b, y*) + RTRDP)]**  Where the weighting factor for the Electrical Bus associated with the meter is:  **RNWF *b, y* = [Max (0.001,** **Max (0,** **BP *r, y*)) \* TLMP *y*] /**  **[image010Max (0.001,** **Max (0,** **BP *r, y*)) \* TLMP *y*]**  Where:  RTRDP = (RNWF  *y* \* RTRDPA *y*)  RNWF *y* = TLMP *y* / TLMP *y*  The summation is over all Resources *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.  The above variables are defined as follows:   | **Variable** | **Unit** | **Description** | | --- | --- | --- | | NMRTETOT *gsc* | MWh | *Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System. | | NMSAMTTOT*gsc* | $ | *Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement. | | RTRMPR *b* | $/MWh | *Real-Time Price for the Energy Metered for each Resource meter at bus*¾The Real-Time price for the Settlement Meter at Electrical Bus *b*, for the 15-minute Settlement Interval. | | MEB *gsc, b* | MWh | *Metered Energy at Bus*¾The metered energy by the Settlement Meter which is not upstream from another Settlement Meter which measures CLR (that is not an ALR) or ESR Load for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy withdrawn. | | RTRDP | $/MWh | *Real-Time Reliability Deployment Price for Energy*¾The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy. | | RTRDPA*y* | $/MWh | *Real-Time Reliability Deployment Price Adder for Energy* ¾The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*¾The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval. | | RTLMP *b, y* | $/MWh | *Real-Time Locational Marginal Price at bus per interval*¾The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*. | | TLMP *y* | second | *Duration of SCED interval per interval*¾The duration of the SCED interval *y*. | | RNWF *b, y* | none | *Net meter Weighting Factor per interval*¾The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters. | | BP *r, y* | MW | *Base Point per Resource per interval*¾The Base Point of Resource *r,* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | MEBC*gsc, b* | MWh | *Metered Energy at Bus (Calculated)* ¾ The calculated energy for the 15-minute Settlement Interval for a Settlement Meter which is upstream from another Settlement Meter which measures CLR (that is not an ALR) or ESR Load. A positive value represents energy produced, and a negative value represents energy withdrawn. This is not adjusted for losses and UFE. | | *gsc* | none | A generation site code. | | *r* | none | A Generation Resource or ESR that is located at the Facility with net metering. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval. | | *b* | none | An Electrical Bus. | |

(5) The Generation Resource SCADA Splitting Percentage for each Resource within a net metering arrangement for the 15-minute Settlement Interval is calculated as follows:

**GSPLITPER *q, r, gsc, p* = GSSPLITSCA *r* /** **GSSPLITSCA *r***

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| GSPLITPER *q, r, gsc, p* | none | *Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. GSPLITPER is calculated by taking the SCADA values (GSSPLITSCA) for a particular Generation Resource *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| GSSPLITSCA *r* | MWh | *Generation Resource SCADA Net Real Power provided via Telemetry*—The net real power provided via telemetry per Resource within the net metering arrangement, integrated for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| *gsc* | none | A generation site code. |
| *r* | none | A Generation Resource that is located at the Facility with net metering. |
| *q* | none | A QSE. |
| *p* | none | A Resource Node Settlement Point. |

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| ***[NPRR1014: Replace paragraph (5) above with the following upon system implementation:]***  (5) The Generation Resource or ESR SCADA Splitting Percentage for each Resource within a net metering arrangement for the 15-minute Settlement Interval is calculated as follows:  **GSPLITPER *q, r, gsc, p* = Max(GSSPLITSCA *r*,0)/** Max(**GSSPLITSCA *r*,0)**  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | GSPLITPER *q, r, gsc, p* | none | *Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. GSPLITPER is calculated by taking the positive SCADA values (GSSPLITSCA) for a particular Generation Resource or ESR *r* that is part of a net metering configuration and dividing by the sum of all positive SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | GSSPLITSCA *r* | MWh | *Generation Resource SCADA Net Real Power provided via Telemetry*—The positive net real power provided via telemetry per Resource within the net metering arrangement, integrated for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | *gsc* | none | A generation site code. | | *r* | none | A Generation Resource or ESR that is located at the Facility with net metering. | | *q* | none | A QSE. | | *p* | none | A Resource Node Settlement Point. | |

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

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

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| RTEIAMTQSETOT *q* | $ | *Real-Time Energy Imbalance Amount QSE Total per QSE*¾The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval. |
| RTEIAMT *q, p* | $ | *Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval. |
| *q* | none | A QSE. |
| *p* | none | A Resource Node Settlement Point. |

***6.6.9 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.

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| ***[NPRR1010, NPRR1014, and NPRR1246: 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 and NPRR1246; 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 Locational Marginal Prices (LMPs), ignoring the Real-Time Reliability Deployment Price Adder for Energy, QSEs that received Ancillary Service awards that are inconsistent with the Real-Time MCPCs, ignoring the Reliability Deployment Price Adders for Ancillary Services, 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 LMPs. The Ancillary Service award is the award received by the QSE that ERCOT identified as inconsistent with Real-Time MCPCs. 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) QSEs with at least one Resource that met the criteria in paragraph (15)(d) of Section 6.5.7.3, Security Constrained Economic Dispatch, that submitted a timely Settlement and billing dispute for each affected Operating Day, consistent with the dispute process described in Section 9.14, Settlement and Billing Dispute Process, shall be considered for additional compensation using the formula in paragraph (1) in Section 6.6.9.1. If the Resource Settlement Point Price at the Resource Node is lower than the Energy Offer Curve or Energy Bid/Offer Curve price, capped per the MOC pursuant to Section 4.4.9.4.1, at the aggregated 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 aggregated Base Point. For purposes of this Settlement and limited to the Settlement Intervals meeting the criteria specified in paragraph (15)(d) of Section 6.5.7.3, SCED Base Points will be used in place of the Emergency Base Point.  (6) 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.  (7) 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.  (8) For each 15-minute Settlement Interval, if the Generation Resource or Energy Storage Resource (ESR) represented by the QSE receives Base Points or Ancillary Service Awards that are inconsistent with prices per paragraph (4) above and has submitted a dispute under paragraph (5) above, the Resource shall only be considered for compensation under paragraph (4) above.  (9) 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.  (10) 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.  (11) 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.  (12) 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.  (13) 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. |

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| ***[NPRR1290: Delete paragraphs (5) and (8) above upon system implementation and renumber accordingly.]*** |

**6.6.9.1 Payment for Emergency Power Increase Directed by ERCOT**

(1) If the Emergency Base Point issued to a Generation Resource is higher than the SCED Base Point immediately before the Emergency Condition or Watch, then ERCOT shall pay the QSE an additional compensation for the Resource at its Resource Node Settlement Point. The payment for a given 15-minute Settlement Interval is calculated as follows:

**EMREAMT *q, r, p* = (-1) \* EMREPR *q, r, p* \* EMRE *q, r, p***

Where:

EMREPR *q, r, p* = Max (0, EBPWAPR *q, r, p* – RTSPP *p*)

EBPWAPR *q, r, p* = (EBPPR *q, r, p, y* \* EBP *q, r, p, y* \* TLMP *y*) **/**

(EBP *q, r, p, y* \* TLMP *y*)

EMRE *q, r, p* = Max (0, Min (AEBP*q, r, p*, RTMG *q, r, p*) – ¼ \* BP *q, r, p*)

AEBP*q, r, p* =  (EBP *q, r, p, y* \* TLMP*y* / 3600)

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| EMREAMT *q, r, p* | $ | *Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| EMREPR *q, r, p* | $/MWh | *Emergency Energy Price per QSE per Settlement Point per Resource*—The compensation rate for the additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| EMRE *q, r, p* | MWh | *Emergency Energy per QSE per Settlement Point per Resource*—The additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| EBPWAPR *q, r, p* | $/MWh | *Emergency Base Point Weighted Average Price per QSE per Settlement Point per Resource*—The weighted average of the energy prices corresponding with the Emergency Base Points on the Energy Offer Curve for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| BP *q, r, p* | MW | *Base Point per QSE per Settlement Point per Resource*—The Base Point of Resource *r* at Resource Node *p* represented by QSE *q* from the SCED prior to the Emergency Condition or Watch. For a Combined Cycle Train, the Resource *r* must be one of the registered Combined Cycle Generation Resources within the Combined Cycle Train. |
| AEBP*q, r, p* | MWh | *Aggregated Emergency Base Point*—The Generation Resource’s aggregated Emergency Base Point, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, AEBP is calculated for the Combined Cycle Train considering all emergency Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train. |
| EBP *q, r, p, y* | MW | *Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. |
| EBPPR *q, r, p, y* | $/MWh | *Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The average incremental energy cost calculated per the Energy Offer Curve, capped by the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap, for the output levels between the SCED Base Point immediately before the Emergency Condition or Watch and the Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.   |  | | --- | | ***[NPRR1216: Replace the definition above with the following upon system implementation:]***  *Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The average incremental energy cost calculated per the Energy Offer Curve, capped by the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap, and by the RTSWCAP, for the output levels between the SCED Base Point immediately before the Emergency Condition or Watch and the Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | |
| RTSPP *p* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval. |
| RTMG *q, r, p* | MWh | *Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| TLMP *y* | second | *Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval. |
| *q* | none | A QSE. |
| *p* | none | A Resource Node Settlement Point. |
| *r* | none | A Generation Resource. |
| *y* | none | An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval. |
| 3600 | none | The number of seconds in one hour. |

(2) The extension of the Energy Offer Curve is used to calculate the Emergency Base Point Price. If the Emergency Base Point MW value is greater than the largest MW value on the Energy Offer Curve submitted by the QSE for the Resource, then the Energy Offer Curve is extended to the Emergency Base Point MW value with a $/MWh value that is the MOC (pursuant to Section 4.4.9.4.1) for the highest MW output on the Energy Offer Curve submitted by the QSE for the Resource.

Q1 Q2 SCED Q3 EBP MW

$/

MWh

P 3

P2

P1

The area under the capped Energy Offer Curve equals

(EBPPR \* (EBP – SCED BP))

Mitigated Offer Cap

Extended portion of Energy Offer Curve

Q1 Q2 SCED Q3 EBP MW

$/

MWh

P 3

P2

P1

The area under the capped Energy Offer Curve equals

(EBPPR \* (EBP – SCED BP))

Mitigated Offer Cap

(3) The total additional compensation to each QSE for emergency power increases of Generation Resources for the 15-minute Settlement Interval is calculated as follows:

**EMREAMTQSETOT *q* = EMREAMT *q, r, p***

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| EMREAMTQSETOT *q* | $ | *Emergency Energy Amount QSE Total per QSE*¾The total of the payments to QSE *q* as additional compensation for emergency power increases of the Generation Resources represented by this QSE for the 15-minute Settlement Interval. |
| EMREAMT *q, r, p* | $ | *Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. |
| *q* | none | A QSE. |
| *p* | none | A Resource Node Settlement Point. |
| *r* | none | A Generation Resource. |

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| ***[NPRR1010, NPRR1014, and NPRR1245: Replace applicable portions of Section 6.6.9.1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1245; or upon system implementation for NPRR1014:]***  **6.6.9.1 Payment for Emergency Operations Settlement**  (1) ERCOT shall pay the QSE additional compensation for the Resource at its Resource Node Settlement Point during the Settlement Intervals that qualify for emergency Settlement as described in Section 6.6.9, Emergency Operations Settlement. The payment for a given 15-minute Settlement Interval is calculated as follows:  **EMREAMT *q, r, p* = (-1) \* (EMREPRGEN *q, r, p* \* EMREGEN *q, r, p*)**  **+ (EMREPRLOAD *q, r, p* \* EMRELOAD *q, r, p*)**  Where:  If any EBP > 0 then:  EMREPRGEN *q, r, p* = Max (0, EBPWAPRGEN *q, r, p* – RTSPP *p*)  EBPWAPRGEN *q, r, p* = (EBPPR *q, r, p, y* \* Max (0.001, EBP *q, r, p, y*) \* TLMP *y*) **/**  (Max (0.001, EBP *q, r, p, y*)\* TLMP *y*)  EMREGEN *q, r, p* = Max (0, Min (AEBPGEN*q, r, p*, RTMG *q, r, p*) – ¼ \* Max (0, BP *q, r, p*))  AEBPGEN*q, r, p* =  (Max (0, EBP *q, r, p, y*) \* TLMP *y* / 3600)  If any EBP < 0 then:  EMREPRLOAD *q, r, p* = Max (0, RTSPP *p* – EBPWAPRLOAD *q, r, p*)  EBPWAPRLOAD *q, r, p* = (EBPPR *q, r, p, y* \* Min (-0.001, EBP *q, r, p, y*) \* TLMP *y*) **/**  (Min (-0.001, EBP *q, r, p, y*)\* TLMP *y*)  EMRELOAD *q, r, p* = Min (0, Max (AEBPLOAD*q, r, p*, RTCL *q, r, p*) – ¼ \* Min (0, BP *q, r, p*))  AEBPLOAD *q, r, p* =  (Min (0, EBP *q, r, p, y*) \* TLMP*y* / 3600)  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | EMREAMT *q, r, p* | $ | *Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EMREPRGEN *q, r, p* | $/MWh | *Emergency Energy Price for Generation per QSE per Settlement Point per Resource*—The compensation rate for the generation produced by Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EMREPRLOAD *q, r, p* | $/MWh | *Emergency Energy Price for Charging Load per QSE per Settlement Point per Resource*—The compensation rate for the charging load for Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. | | EMREGEN *q, r, p* | MWh | *Emergency Energy for Generation per QSE per Settlement Point per Resource*—The generation produced by Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EMRELOAD *q, r, p* | MWh | *Emergency Energy for Charging Load per QSE per Settlement Point per Resource*—The charging load for Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. | | EBPWAPRGEN *q, r, p* | $/MWh | *Emergency Base Point Weighted Average Price for Generation per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the positive Emergency Base Points, for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EBPWAPRLOAD *q, r, p* | $/MWh | *Emergency Base Point Weighted Average Price for Charging Load per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the negative Emergency Base Points, for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. | | BP *q, r, p* | MW | *Base Point per QSE per Settlement Point per Resource*—The Base Point of Resource *r* at Resource Node *p* represented by QSE *q* from the SCED prior to the Emergency Condition or Watch. For a Combined Cycle Train, the Resource *r* must be one of the registered Combined Cycle Generation Resources within the Combined Cycle Train. | | AEBPGEN*q, r, p* | MWh | *Aggregated Emergency Base Point for Generation*—The aggregation of the positive Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, AEBP is calculated for the Combined Cycle Train considering all emergency Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train. | | AEBPLOAD*q, r, p* | MWh | *Aggregated Emergency Base Point for Charging Load*—The aggregation of the negative Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. | | EBP *q, r, p, y* | MW | *Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | EBPPR *q, r, p, y* | $/MWh | *Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The price on the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the Emergency Base Point for Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. The Energy Offer Curve shall be capped by the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap and the Energy Bid/Offer Curve shall be capped by the maximum RTSPP at the Settlement Point for the Operating Day, per paragraph (12) of Section 6.6.9. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTSPP *p* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval. | | RTMG *q, r, p* | MWh | *Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTCL *q, r, p* | MWh | *Real-Time Charging Load per QSE per Resource per Settlement Point*—The charging load for Resource *r* at Resource Node *p* represented by the QSE *q,* represented as a negative value,for the 15-minute Settlement Interval. | | TLMP *y* | second | *Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval. | | *q* | none | A QSE. | | *p* | none | A Resource Node Settlement Point. | | *r* | none | A Generation Resource or ESR. | | *y* | none | An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval. | | 3600 | none | The number of seconds in one hour. |   (2) ERCOT shall pay the QSE additional compensation for the Resource at its Resource Node Settlement Point during the Settlement Intervals that qualify for emergency Settlement as described in Section 6.6.9, Emergency Operations Settlement. The payment for a given 15-minute Settlement Interval is calculated as follows:  **EMREAMT *q, r, p*  = Min (0, RTENET *q, r, p* + RTASNET *q, r*)**  (a) Where the Real-Time Energy Net Revenue is calculated as follows:  RTENET *q, r, p* = RTEREV*q, r, p* - RTEREVT*q, r, p*  Where:  RTEREV*q, r, p* = RTSPP *p* \* (EMREGEN *q, r, p* + EMRELOAD *q, r, p*)  RTEREVT*q, r, p* = EBPWAPRGEN *q, r, p* \* EMREGEN *q, r, p* +  EBPWAPRLOAD *q, r, p* \* EMRELOAD *q, r, p*  If any EBP > 0 then:  EBPWAPRGEN *q, r, p* = (EBPPR *q, r, p, y* \* Max (0.001, EBP *q, r, p, y*) \* TLMP *y*) **/**  (Max (0.001, EBP *q, r, p, y*)\* TLMP *y*)  EMREGEN *q, r, p* = Max (0, Min (AEBPGEN*q, r, p*, RTMG *q, r, p*))  AEBPGEN*q, r, p* =  (Max (0, EBP *q, r, p, y*) \* TLMP*y* / 3600)  If any EBP < 0 then:  EBPWAPRLOAD *q, r, p* = (EBPPR *q, r, p, y* \* Min (-0.001, EBP *q, r, p, y*) \* TLMP *y*) **/**  (Min (-0.001, EBP *q, r, p, y*)\* TLMP *y*)  EMRELOAD *q, r, p* = Min (0, Max (AEBPLOAD*q, r, p*, RTCL *q, r, p*))  AEBPLOAD *q, r, p* =  (Min (0, EBP *q, r, p, y*) \* TLMP*y* / 3600)  (b) Where the Real-Time Ancillary Services Net Revenue is calculated as follows:  RTASNET*q, r* = RTRUNET *q, r*+ RTRDNET *q, r* + RTNSNET *q, r* + RTRRNET *q, r* + RTECRNET *q, r*  Where for Reg-Up:  RTRUNET *q, r*  = RTRUREV *q, r* - (¼) \* RTRUREVT *q, r, p*  RTRUREVT*q, r, p* = RTRUWAPR *q, r, p* \* RTRUAWD *q, r*  RTRUWAPR *q, r, p* = (RTRUOPR *q, r, y* \* Max (0.001, RTRUAWDS *q, r, y*) \* TLMP *y*) **/**  (Max (0.001, RTRUAWDS *q, r, y*)\* TLMP *y*)  Where for Reg-Down:  RTRDNET *q, r* = RTRDREV *q, r* - (¼) \* RTRDREVT *q, r, p*  RTRDREVT*q, r, p* = RTRDWAPR *q, r, p* \* RTRDAWD *q, r*  RTRDWAPR *q, r, p* = (RTRDOPR *q, r, y* \* Max (0.001, RTRDAWDS *q, r, y*) \* TLMP *y*) **/**  (Max (0.001, RTRDAWDS *q, r, y*)\* TLMP *y*)  Where for RRS:  RTRRNET *q, r*  = RTRRREV *q, r* - (¼) \* RTRRREVT *q, r, p*  RTRRREVT*q, r, p* = RTRRWAPR *q, r, p* \* RTRRAWD *q, r*  RTRRWAPR *q, r, p* = (RTRROPR *q, r, y* \* Max (0.001, RTRRAWDS *q, r, y*) \* TLMP *y*) **/** (Max (0.001, RTRRAWDS *q, r, y*)\* TLMP *y*)  Where for Non-Spin:  RTNSNET *q, r*  = RTNSREV *q, r* - (¼) \* RTNSREVT *q, r, p*  RTNSREVT*q, r, p* = RTNSWAPR *q, r, p* \* RTNSAWD *q, r*  RTNSWAPR *q, r, p* = (RTNSOPR *q, r, y* \* Max (0.001, RTNSAWDS *q, r, y*) \* TLMP *y*) **/**(Max (0.001, RTNSAWDS *q, r, y*)\* TLMP *y*)  Where for ERCOT Contingency Reserve (ECRS):  RTECRNET *q, r*  = RTECRREV *q, r* - (¼) \* RTECRREVT *q, r, p*  RTECRREVT*q, r, p* = RTECRWAPR *q, r, p* \* RTECRAWD *q, r*  RTECRWAPR *q, r, p* = (RTECROPR *q, r, y* \* Max (0.001, RTECRAWDS *q, r, y*) \* TLMP *y*) **/** (Max (0.001, RTECRAWDS *q, r, y*)\* TLMP *y*)  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | EMREAMT *q, r, p* | $ | *Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTENET *q, r, p* | $ | *Real-Time Energy Net Revenue*—The net difference between the Real-Time Energy Revenue and the Real-Time Energy Revenue Target for QSE *q* for Resource *r* at Resource node *p* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTASNET *q, r* | $ | *Real-Time Ancillary Service Net Revenue*—The sum of the Ancillary Service net revenues for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTEREV *q, r, p* | $ | *Real-Time Energy Revenue*—The calculated Real-Time energy revenue at the RTSPP for QSE *q* calculated forResource *r* at Resource node *p* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EMREGEN *q, r, p* | MWh | *Emergency Energy for Generation per QSE per Settlement Point per Resource*—The generation produced by Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EMRELOAD *q, r, p* | MWh | *Emergency Energy for Charging Load per QSE per Settlement Point per Resource*—The charging load for Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. | | RTEREVT *q, r, p* | $ | *Real-Time Energy Revenue Target*—The energy revenue target at the EBPWAPRGEN and EBPWAPRLOAD of the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EBPWAPRGEN *q, r, p* | $/MWh | *Emergency Base Point Weighted Average Price for Generation per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the positive Emergency Base Points for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | EBPWAPRLOAD *q, r, p* | $/MWh | *Emergency Base Point Weighted Average Price for Charging Load per QSE per Settlement Point per Resource*—The weighted average of the Emergency Base Point Prices corresponding with the negative Emergency Base Points, for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. | | AEBPGEN*q, r, p* | MWh | *Aggregated Emergency Base Point for Generation*—The aggregation of the positive Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, AEBP is calculated for the Combined Cycle Train considering all emergency Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train. | | AEBPLOAD*q, r, p* | MWh | *Aggregated Emergency Base Point for Charging Load*—The aggregation of the negative Emergency Base Points for the Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval. | | EBP *q, r, p, y* | MW | *Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | EBPPR *q, r, p, y* | $/MWh | *Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The price on the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the Emergency Base Point for Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. The Energy Offer Curve shall be capped by the MOC pursuant to Section 4.4.9.4.1, Mitigated Offer Cap, and the Energy Bid/Offer Curve shall be capped by the maximum RTSPP at the Settlement Point for the Operating Day, per paragraph (12) of Section 6.6.9. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTSPP *p* | $/MWh | *Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval. | | RTMG *q, r, p* | MWh | *Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTCL *q, r, p* | MWh | *Real-Time Charging Load per QSE per Resource per Settlement Point*—The charging load for Resource *r* at Resource Node *p* represented by the QSE *q,* represented as a negative value,for the 15-minute Settlement Interval. | | RTRUNET *q, r* | $ | *Real-Time Reg-Up Net Revenue*—The difference between the Real-Time Reg-Up Revenue and the Real-Time Reg-Up Revenue Target for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRDNET *q, r* | $ | *Real-Time Reg-Down Net Revenue*—The difference between calculated revenue for the Real-Time Reg-Down Revenue and the Real-Time Reg-Down Revenue Target for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRRNET *q, r* | $ | *Real-Time Responsive Reserve Net Revenue*—The difference between Real-Time RRS Revenue and the Real-Time RRS Revenue Target for QSE *q* for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTNSNET *q, r* | $ | *Real-Time Non-Spin Net Revenue*—The difference between Real-Time Non-Spin Revenue and the Real-Time Non-Spin Revenue Target for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTECRNET *q, r* | $ | *Real-Time ERCOT Contingency Reserve Service Net Revenue*—The difference between Real-Time ECRS Revenue and the Real-Time ECRS Revenue Target for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRUREV *q, r* | $ | *Real-Time Reg-Up Revenue*—The calculated Real-Time Reg-Up revenue for QSE *q* calculated forResource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRDREV *q, r* | $ | *Real-Time Reg-Down Revenue*—The calculated Real-Time Reg-Down revenue for QSE *q* calculated forResource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRRREV *q, r* | $ | *Real-Time Responsive Reserve Revenue*—The calculated Real-Time RRS revenue for QSE *q* calculated forResource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTNSREV *q, r* | $ | *Real-Time Non-Spin Revenue*—The calculated Real-Time Non-Spin revenue for QSE *q* calculated forResource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTECRREV *q, r* | $ | *Real-Time ERCOT Contingency Reserve Service Revenue*—The calculated Real-Time ECRS revenue for QSE *q* calculated forResource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRUREVT *q, r, p* | $ | *Real-Time Reg-Up Revenue Target*—The revenue target of the Reg-Up award to Resource *r* at Resource Node *p* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRDREVT *q, r, p* | $ | *Real-Time Reg-Down Revenue Target*—The revenue target of the Reg-Down award to Resource *r* at Resource Node *p* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRRREVT *q, r, p* | $ | *Real-Time Responsive Reserve Revenue Target*—The revenue target of the RRS award to Resource *r* at Resource Node *p* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTNSREVT *q, r, p* | $ | *Real-Time Non-Spin Revenue Target*—The revenue target of the Non-Spin award to Resource *r* at Resource Node *p* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTECRREVT *q, r, p* | $ | *Real-Time ERCOT Contingency Reserve Service Revenue Target*—The revenue target of the ECRS award to Resource *r* at Resource Node *p* represented by QSE *q* based on the Ancillary Service Offer for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRUWAPR *q, r, p* | $/MW | *Real-Time Reg-Up Weighted-Average Price*—The weighted average of the Ancillary Service Offer prices corresponding with the Reg-Up awards from the Ancillary Service Offer for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRDWAPR *q, r, p* | $/MW | *Real-Time Reg-Down Weighted-Average Price*—The weighted average of the Ancillary Service Offer prices corresponding with the Reg-Down awards from the Ancillary Service Offer for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRRWAPR *q, r, p* | $/MW | *Real-Time Responsive Reserve Weighted-Average Price*—The weighted average of the Ancillary Service Offer prices corresponding with the RRS awards from the Ancillary Service Offer for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTNSWAPR *q, r, p* | $/MW | *Real-Time Non-Spin Weighted-Average Price*—The weighted average of the Ancillary Service Offer prices corresponding with the Non-Spin awards from the Ancillary Service Offer for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTECRWAPR *q, r, p* | $/MW | *Real-Time ERCOT Contingency Reserve Service Weighted-Average Price*—The weighted average of the Ancillary Service Offer prices corresponding with the ECRS awards from the Ancillary Service Offer for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRUAWD *q, r* | MW | *Real-Time Reg-Up Award per Resource per QSE*—The Reg-Up amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRDAWD *q, r* | MW | *Real-Time Reg-Down Award per Resource per QSE*—The Reg-Down amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRRAWD *q, r* | MW | *Real-Time Responsive Reserve Award per Resource per QSE*—The RRS amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTNSAWD *q, r* | MW | *Real-Time Non-Spin Award per Resource per QSE*—The Non-Spin amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTECRAWD *q, r* | MW | *Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE*—The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTRUOPR *q, r, y* | $/MW | *Real-Time Reg-Up Offer Price*—The price from the submitted Ancillary Service Offer at the Reg-Up award of Resource *r* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTRDOPR *q, r, y* | $/MW | *Real-Time Reg-Down Offer Price*—The price from the submitted Ancillary Service Offer at the Reg-Down award of Resource *r* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTRROPR *q, r, y* | $/MW | *Real-Time Responsive Reserve Offer Price*—The price from the submitted Ancillary Service Offer at the RRS award of Resource *r* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTNSOPR *q, r, y* | $/MW | *Real-Time Non-Spin Offer Price*—The price from the submitted Ancillary Service Offer at the Non-Spin award of Resource *r* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTECROPR *q, r, y* | $/MW | *Real-Time ERCOT Contingency Reserve Service Offer Price*—The price from the submitted Ancillary Service Offer at the ECRS award of Resource *r* represented by QSE *q* for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTRUAWDS *q, r, y* | MW | *Real-Time Reg-Up Award per Resource per QSE per SCED interval*—The Reg-Up amount awarded to QSE *q* for Resource *r* in Real-Timefor the SCED interval *y.* Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTRDAWDS *q, r, y* | MW | *Real-Time Reg-Down Award per Resource per QSE per SCED interval*—The Reg-Down amount awarded to QSE *q* for Resource *r* in Real-Timefor the SCED interval *y.* Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTRRAWDS *q, r, y* | MW | *Real-Time Responsive Reserve Award per Resource per QSE per SCED interval*—The RRS amount awarded to QSE *q* for Resource *r* in Real-Timefor the SCED interval *y.* Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTNSAWDS *q, r, y* | MW | *Real-Time Non-Spin Award per Resource per QSE per SCED interval*—The Non-Spin amount awarded to QSE *q* for Resource *r* in Real-Timefor the SCED interval *y.* Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTECRAWDS *q, r, y* | MW | *Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE per SCED interval*—The ECRS amount awarded to QSE *q* for Resource *r* in Real-Timefor the SCED interval *y.* Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | TLMP *y* | second | *Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval. | | *q* | none | A QSE. | | *p* | none | A Resource Node Settlement Point. | | *r* | none | A Generation Resource or ESR. | | *y* | none | An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval. | | 3600 | none | The number of seconds in one hour. |   (3) The extension of the Energy Offer Curve or Energy Bid/Offer Curve and Mitigated Offer Cap (MOC) is used to calculate the Emergency Base Point Price (EBPPR). If the Emergency Base Point MW value is greater than the largest MW value on the Energy Offer Curve or Energy Bid/Offer Curve submitted by the QSE for the Resource, or the Resource’s MOC, then the Energy Offer Curve, Energy Bid/Offer Curve, or MOC is extended to the Emergency Base Point MW value with a $/MWh value that is equal to the highest $/MWh value on the applicable curve. If the Emergency Base Point MW value is lower than the lowest MW value on the Energy Offer Curve or Energy Bid/Offer Curve submitted by the QSE for the Resource, or the Resource’s MOC, then the Energy Offer Curve, Energy Bid/Offer Curve or MOC is extended to the Emergency Base Point MW value with a $/MWh value that is equal to the lowest $/MWh value on the applicable curve.  (4) If the Real-Time Ancillary Service Award is greater than the total quantity from the Resource-Specific Ancillary Service Offer submitted by the QSE, then the Real-Time Ancillary Service Offer price for the Resource will be equal to the highest price from the submitted Resource-Specific Ancillary Service Offer for the Ancillary Service type.  (5) The total additional compensation to each QSE for emergency Settlement of Resources for the 15-minute Settlement Interval is calculated as follows:  **EMREAMTQSETOT *q* = EMREAMT *q, r, p***  The above variables are defined as follows:   | **Variable** | **Unit** | **Definition** | | --- | --- | --- | | EMREAMTQSETOT *q* | $ | *Emergency Energy Amount QSE Total per QSE*¾The total of the payments to QSE *q* as additional compensation for additional energy or Ancillary Services of the Resources represented by this QSE for the 15-minute Settlement Interval. | | EMREAMT *q, r, p* | $ | *Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy or Ancillary Services produced or consumed by Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition or Watch, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | *q* | none | A QSE. | | *p* | none | A Resource Node Settlement Point. | | *r* | none | A Generation Resource or ESR. | |

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| * ***[NPRR1010 and NPRR1245: Insert Section 6.7.5.5 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***   **6.7.5.5 Non-Spinning Reserve Service Payments and Charges**  (1) Non-Spin Imbalance Payment or Charge:  **RTNSIMBAMT *q* = (-1) \* [[RTNSREV *q, r* – (1/4) \* (PCNSR *r, q, DAM* \* RTMCPCNS)] – (1/4) \* (DASANSQ *q* \* RTMCPCNS) + (1/4) \* (NSTP *q* – NSTS *q*) \* RTMCPCNS]**  **Where:**  **RTNSREV *q, r  =* (1/4) \* RTNSAWD *q, r* \* RTMCPCNSR *q, r***  **RTMCPCNSR *q, r =*  (NSRWF *q, r, y* \* (RTMCPCNSS *y* + RTRDPANSS *y*))**  **RTNSAWD *q, r*  =  (RNWF *y*\* RTNSAWDS *q, r, y*)**  **Where:**  NSRWF *q, r, y*= [max(0.001, RTNSAWDS *q, r, y*) \* TLMP *y*] / [max(0.001,  RTNSAWDS *q, r, y*) \* TLMP *y*]  **And:**  RNWF *y* = TLMP *y* / TLMP *y*   * The above variables are defined as follows:  | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTNSIMBAMT *q* | $ | *Real-Time Non-Spin Imbalance Amount for the QSE*—The total payment or charge to QSE *q* for the Real-Time Non-Spin imbalance for each 15-minute Settlement Interval. | | RTNSAWD *q, r* | MW | *Real Time Non-Spin Award per Resource per QSE*—The Non-Spin amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTNSREV *q, r* | $ | *Real-Time Non-Spin Revenue*—The Real-Time Non-Spin revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTNSAWDS *q, r, y* | MW | *Real Time Non-Spin Award per Resource per QSE* *per SCED interval*—The Non-Spin Amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y.* Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTMCPCNSR *q, r* | $/MW | *Real-Time Market Clearing Price for Capacity for Non-Spin per Resource per QSE*¾The Real-Time MCPC for Non-Spin for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTMCPCNSS *y* | $/MW | *Real-Time Market Clearing Price for Capacity for Non-Spin per SCED Interval*—The Real-Time MCPC for Non-Spin for the SCED interval *y.* | | PCNSR *r, q, DAM* | MW | *Procured Capacity for Non-Spin per Resource per QSE in DAM*—The Non-Spin capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTMCPCNS | $/MW | *Real-Time Market Clearing Price for Capacity for Non-Spin*—The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval. | | RTRDPANSS *y* | $/MW | *Real-Time Reliability Deployment Price Adder for Ancillary Service for Non-Spin per SCED interval*—The Real-Time price adder for Non-Spin that captures the impact of reliability deployments on Non-Spin prices for the SCED interval *y*. | | DASANSQ *q* | MW | *Day-Ahead Self-Arranged Non-Spin Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour. | | NSTP *q* | MW | *Trade Purchases for Non-Spin for the QSE*—The trade purchases for QSE *q* for Non-Spin for the Operating Hour. | | NSTS *q* | MW | *Trade Sales for Non-Spin for the QSE—*The trade sales for QSE *q* for Non-Spin for the Operating Hour. | | TLMP *y* | second | *Duration of SCED interval per interval*—The duration of the SCED interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service award calculation for the portion of the SCED interval *y* within the Settlement Interval. | | NSRWF *q, r, y* | none | *Non-Spin Resource Node Weighting Factor per interval*—The Non-Spin Resource weight, based on Non-Spin awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval*.* Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | *r* | none | A Resource. | | *q* | none | A QSE. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. |   (2) Non-Spin Only Charge:  **RTNSOAMT *q* = (1/4) \* DANSOAWD *q* \* RTMCPCNS**   * The above variables are defined as follows:  | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTNSOAMT *q* | $ | *Real-Time Non-Spin Only Amount for the QSE*—The total charge to QSE *q* in Real-Time for Non-Spin only award for each 15-minute Settlement Interval. | | DANSOAWD *q* | MW | *Day-Ahead Non-Spin Only Award for the QSE*¾The Non-Spin only capacity awarded in the DAM to the QSE *q* for the Operating Hour. | | RTMCPCNS | $/MW | *Real-Time Market Clearing Price for Capacity for Non-Spin*—The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval. | | *q* | none | A QSE. |   (3) Non-Spin Trade Overage Charge:  **RTNSTOAMT *q* = (1/4) \* RTNSTO *q* \* RTMCPCNS**   * The above variables are defined as follows:  | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTNSTOAMT *q* | $ | *Real-Time Non-Spin Trade Overage Amount for the QSE*—The total charge to QSE *q* in Real-Time for Non-Spin trade overages for each 15-minute Settlement Interval. | | RTNSTO *q* | MW | *Real-Time Non-Spin Trade Overage for the QSE*¾The quantity of submitted Non-Spin trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour. | | RTMCPCNS | $/MW | *Real-Time Market Clearing Price for Capacity for Non-Spin*—The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval. | | *q* | none | A QSE. | |

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| * ***[NPRR1010 and NPRR1245: Insert Section 6.7.5.6 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]***   **6.7.5.6 ERCOT Contingency Reserve Service Payments and Charges**  (1) ECRS Imbalance Payment or Charge:  **RTECRIMBAMT *q* = (-1) \* [[RTECRREV*q, r* – (1/4) \* (PCECRR *r, q, DAM* \***  **RTMCPCECR)] – (1/4) \* (DASAECRQ *q* \* RTMCPCECR) + (1/4) \* (ECRTP *q* – ECRTS *q*) \* RTMCPCECR]**  **Where:**  **RTECRREV *q, r  =* (1/4) \* RTECRAWD *q, r* \* RTMCPCECRR *q, r***  **RTMCPCECRR *q, r =* (ECRRWF *q, r, y* \* (RTMCPCECRS *y* + RTRDPAECRS *y))***  **RTECRAWD *q, r*  =  (RNWF *y*\* RTECRAWDS *q, r, y*)**  Where:  ECRRWF *q, r, y* = [max(0.001, RTECRAWDS *q, r, y*) \* TLMP *y*] / [max(0.001,  RTECRAWDS *q, r, y*) \* TLMP *y*]  And:  RNWF *y* = TLMP *y* / TLMP *y*   * The above variables are defined as follows:  | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTECRIMBAMT *q* | $ | *Real-Time ERCOT Contingency Reserve Service Imbalance Amount for the QSE—*The total payment or charge to QSE *q* for the Real-Time ECRS imbalance for each 15-minute Settlement Interval. | | RTECRAWD q, r | MW | *Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE*¾The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTECRREV *q, r* | $ | *Real-Time ERCOT Contingency Reserve Service Revenue*—The Real-Time ECRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTECRAWDS *q, r, y* | MW | *Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE per SCED interval*—The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y.* Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTMCPCECRR *q, r* | $/MW | *Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per Resource per QSE*¾The Real-Time MCPC for ECRS for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train. | | RTMCPCECRS *y* | $/MW | *Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per SCED Interval*—The Real-Time MCPC for ECRS for the SCED interval *y.* | | PCECRR *r, q, DAM* | MW | *Procured Capacity for ERCOT Contingency Reserve Service per Resource per QSE in DAM*—The ECRS capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | RTMCPCECR | $/MW | *Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service*—The Real-Time MCPC for ECRS for the 15-minute Settlement Interval. | | RTRDPAECRS *y* | $/MW | *Real-Time Reliability Deployment Price Adder for Ancillary Service for ERCOT Contingency Reserve Service per SCED interval*—The Real-Time price adder for ECRS that captures the impact of reliability deployments on ECRS prices for the SCED interval *y*. | | DASAECRQ *q* | MW | *Day-Ahead Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE*—The self-arranged ECRS quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour. | | ECRTP *q* | MW | *Trade Purchases for ERCOT Contingency Reserve Service for the QSE—*The trade purchases for QSE *q* for ECRS for the Operating Hour. | | ECRTS *q* | MW | *Trade Sales for ERCOT Contingency Reserve Service for the QSE—*The trade sales for QSE *q* for ECRS for the Operating Hour. | | TLMP *y* | second | *Duration of SCED interval per interval*—The duration of the SCED interval *y*. | | RNWF *y* | none | *Resource Node Weighting Factor per interval*—The weight used in the Ancillary Service award calculation for the portion of the SCED interval *y* within the Settlement Interval. | | ECRRWF *q, r, y* | none | *ERCOT Contingency Reserve Service Resource Node Weighting Factor per interval*—The ECRS Resource weight, based on ECRS awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. | | *r* | none | A Resource. | | *q* | none | A QSE. | | *y* | none | A SCED interval in the 15-minute Settlement Interval. |   (2) ECRS Only Charge:  **RTECROAMT *q* = (1/4) \* DAECROAWD *q* \* RTMCPCECR**   * The above variables are defined as follows:  | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTECROAMT *q* | $ | *Real-Time ERCOT Contingency Reserve Service Only Amount for the QSE—*The total charge to QSE *q* in Real-Time for ECRS only awards for each 15-minute Settlement Interval. | | DAECROAWD *q* | MW | *Day-Ahead ERCOT Contingency Service Only Award for the QSE*¾The ECRS only capacity awarded in the DAM to the QSE *q* for the Operating Hour. | | RTMCPCECR | $/MW | *Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service*—The Real-Time MCPC for ECRS for the 15-minute Settlement Interval. | | *q* | none | A QSE. |   (3) ECRS Trade Overage Charge:  **RTECRTOAMT *q* = (1/4) \* RTECRTO *q* \* RTMCPCECR**   * The above variables are defined as follows:  | **Variable** | **Unit** | **Description** | | --- | --- | --- | | RTECRTOAMT *q* | $ | *Real-Time ERCOT Contingency Reserve Service Trade Overage Amount for the QSE*—The total charge to QSE *q* in Real-Time for ECRS trade overages for each 15-minute Settlement Interval. | | RTECRTO *q* | MW | *Real-Time ERCOT Contingency Reserve Service Trade Overage for the QSE*¾The quantity of submitted ECRS trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour. | | RTMCPCECR | $/MW | *Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service*—The Real-Time MCPC for ECRS for the 15-minute Settlement Interval. | | *q* | none | A QSE. | |

**7.9.1.3 Minimum and Maximum Resource Prices**

(1) For purposes of Section 7.9.1, Day-Ahead CRR Payments and Charges, Settlements data published to the Market Information System (MIS) Secure Area shall include the association of the Resource Category for each Generation Resource. The following prices specified in paragraphs (2) and (3) below are used in the CRR hedge value calculation for CRRs settled in the DAM.

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| ***[NPRR1014 and NPRR1188: Replace applicable portions of paragraph (1) above with the following upon system implementation:]***  (1) For purposes of Section 7.9.1, Day-Ahead CRR Payments and Charges, Settlements data published to the Market Information System (MIS) Secure Area shall include the association of the Resource Category for each Generation Resource, identify Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs), and identify Energy Storage Resources (ESRs). The following prices specified in paragraphs (2) and (3) below are used in the CRR hedge value calculation for CRRs settled in the DAM. |

(2) Minimum Resource Prices of source Settlement Points are:

**MINRESPR** *j* **= Min ( MINRESRPR** *j, r* **)** *r*

Where:

Minimum Resource Prices for Resources located at source Settlement Points (**MINRESRPR** *j, r*) are:

(a) Nuclear = -$20.00/MWh;

(b) Hydro = -$20.00/MWh;

(c) Coal and Lignite = $0.00/MWh;

(d) Combined Cycle greater than 90 MW = Fuel Index Price (FIP) \* 5 MMBtu/MWh;

(e) Combined Cycle less than or equal to 90 MW = FIP \* 6 MMBtu/MWh;

(f) Gas -Steam Supercritical Boiler = FIP \* 6.5 MMBtu/MWh;

(g) Gas Steam Reheat Boiler = FIP \* 7.5 MMBtu/MWh;

(h) Gas Steam Non-Reheat or Boiler without Air-Preheater = FIP \* 10.5 MMBtu/MWh;

(i) Simple Cycle greater than 90 MW = FIP \* 10 MMBtu/MWh;

(j) Simple Cycle less than or equal to 90 MW = FIP \* 11 MMBtu/MWh;

(k) Diesel = FIP \* 12 MMBtu/MWh;

(l) Wind = -$35/MWh;

(m) PhotoVoltaic (PV) = -$10;

(n) Reliability Must-Run (RMR) Resource = RMR contract price Energy Offer Curve at Low Sustained Limit (LSL); and

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| ***[NPRR1188: Insert item (o) below upon system implementation and renumber accordingly:]***  (o) CLR = $100/MWh; and |

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| ***[NPRR1014: Insert item (p) below upon system implementation and renumber accordingly:]***  (p) ESR = -$20/MWh; and |

(o) Other = -$20/MWh.

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| MINRESPR *j* | $/MWh | *Minimum Resource Price for source*—The lowest Minimum Resource Price for the Resources located at the source Settlement Point *j*. |
| MINRESRPR *j* | $/MWh | *Minimum Resource Price for Resource*—The Minimum Resource Price for the Resources located at the source Settlement Point *j*. |
| *r* | none | A Generation Resource located at the source Settlement Point *j*.   |  | | --- | | ***[NPRR1014 and NPRR1188: Replace applicable portions of the definition above with the following upon system implementation:]***  A Generation Resource, CLR that is not an ALR, or ESR located at the source Settlement Point *j*. | |
| *j* | none | A source Settlement Point. |

(3) Maximum Resource Prices of sink Settlement Points are:

**MAXRESPR** *k* **= Max (MAXRESRPR** *k, r* **)** *r*

Where:

Maximum Resource Prices for Resources located at sink Settlement Points **(MAXRESRPR** *k, r* **)** are:

(a) Nuclear = $15.00/MWh;

(b) Hydro = $10.00/MWh;

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

(d) Combined Cycle greater than 90 MW = FIP \* 9 MMBtu/MWh;

(e) Combined Cycle less than or equal to 90 MW = FIP \* 10 MMBtu/MWh;

(f) Gas -Steam Supercritical Boiler = FIP \* 10.5 MMBtu/MWh;

(g) Gas Steam Reheat Boiler = FIP \* 11.5 MMBtu/MWh;

(h) Gas Steam Non-Reheat or Boiler without Air-Preheater = FIP \* 14.5 MMBtu/MWh;

(i) Simple Cycle greater than 90 MW = FIP \* 14 MMBtu/MWh;

(j) Simple Cycle less than or equal to 90 MW = FIP \* 15 MMBtu/MWh;

(k) Diesel = FIP \* 16 MMBtu/MWh;

(l) Wind = $0/MWh;

(m) PV = $0/MWh;

(n) RMR Resource = RMR contract price Energy Offer Curve at High Sustained Limit (HSL); and

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| ***[NPRR1188: Insert item (o) below upon system implementation and renumber accordingly:]***  (o) CLR = The effective Value of Lost Load (VOLL); and |

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| ***[NPRR1014: Insert item (p) below upon system implementation and renumber accordingly:]***  (p) ESR = $100/MWh; and |

(o) Other = $100/MWh.

The above variables are defined as follows:

| **Variable** | **Unit** | **Definition** |
| --- | --- | --- |
| MAXRESPR *k* | $/MWh | *Maximum Resource Price for source*—The highest Maximum Resource Price for the Resources located at the sink Settlement Point *k*. |
| MAXRESRPR *k* | $/MWh | *Maximum Resource Price for Resource*—The Maximum Resource Price for the Resources located at the sink Settlement Point *k*. |
| *r* | none | A Generation Resource located at the sink Settlement Point *k*.   |  | | --- | | ***[NPRR1014 and NPRR1188: Replace applicable portions of the definition above with the following upon system implementation:]***  A Generation Resource, CLR that is not an ALR, or ESR located at the sink Settlement Point *k*. | |
| *k* | none | A sink Settlement Point. |

**8.1.1.2.1.2 Responsive Reserve Qualification**

(1) RRS may be provided by:

(a) On-Line Generation Resource capacity;

(b) Resources capable of providing FFR;

(c) Generation Resources operating in the synchronous condenser fast-response mode;

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

(e) Controllable Load Resources (CLRs).

(2) The amount of RRS provided by individual Generation Resources or CLRs is limited by the ERCOT-calculated maximum MW amount of RRS for the Generation Resource or CLR subject to its verified droop performance as described in the Nodal Operating Guide. The default value for any newly qualified Generation Resource or CLR shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide.

(3) A QSE’s Load Resource must be loaded and capable of unloading the scheduled amount of RRS within ten minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays with settings as specified by the Operating Guides.

(4) Any QSE providing RRS shall provide communications equipment to provide ERCOT with telemetry for the output of the Resource.

(5) Resources capable of FFR providing RRS must provide a telemetered output signal, including breaker status and status of the frequency detection device.

(6) Each QSE shall ensure that each Resource is able to meet the Resource’s obligations to provide the Ancillary Service Resource Responsibility. Each Resource providing RRS must meet additional technical requirements specified in this Section.

(7) Generation Resources providing RRS shall have their Governors in service.

(8) Generation Resources and Resources capable of FFR providing RRS shall have a Governor droop setting that is no greater than 5.0%.

(9) Resources may be provisionally qualified by ERCOT to provide RRS for 90 days. Within the 90-day provisional window, a Resource must successfully complete one of the Governor tests identified in the Nodal Operating Guide Section 8, Attachment C, Turbine Governor Speed Tests, before being declared fully qualified to provide RRS.

(10) A qualification test for each Resource to provide RRS is conducted during a continuous eight-hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements:

(a) At any time during the window, which is selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE that it is to provide an amount of RRS from its Resource to be qualified equal to the amount for which the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) For Generation Resources desiring qualification to provide RRS, ERCOT shall send a signal to the Resource’s QSE to deploy RRS indicating the MW amount. ERCOT shall monitor the QSE’s telemetry of the Resource’s Ancillary Service Schedule for an update within 15 seconds. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.2, Responsive Reserve Service Energy Deployment Criteria. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource’s qualification to provide RRS.

(c) For CLRs desiring qualification to provide RRS, ERCOT shall send a signal to the Resource’s QSE to deploy RRS indicating the MW amount. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.2. ERCOT shall evaluate the response of the CLR given the current operating conditions of the system and determine the CLR’s qualification to provide RRS.

(d) For Load Resources, excluding CLRs, desiring qualification to provide RRS, ERCOT shall deploy RRS indicating the MW amount. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.2.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing RRS and shall provide a copy of the certificate to the QSE and the Resource Entity.

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| --- |
| * ***[NPRR1011 and NPRR1014: Replace applicable portions of Section 8.1.1.2.1.2 above with the following upon system implementation for NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]***   **8.1.1.2.1.2 Responsive Reserve Qualification**  (1) RRS may be provided by:  (a) On-Line Generation Resource capacity;  (b) Resources capable of providing FFR;  (c) Generation Resources operating in the synchronous condenser fast-response mode;  (d) Load Resources controlled by high-set under-frequency relays;  (e) Controllable Load Resources (CLRs); and  (f) Energy Storage Resources (ESRs).  (2) The amount of RRS provided by individual Generation Resources, CLRs, or ESRs is limited by the ERCOT-calculated maximum MW amount of RRS for the Generation Resource, CLR, or ESR subject to its verified droop performance as described in the Nodal Operating Guide. The default value for any newly qualified Generation Resource, CLR, or ESR shall be 20% of its Maximum Droop Response Range (MDRR). A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide.  (3) A QSE’s Load Resource must be loaded and capable of unloading the scheduled amount of RRS within ten minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays with settings as specified by the Operating Guides.  (4) Any QSE representing a Resource qualified to provide RRS shall provide communications equipment to provide ERCOT with telemetry for the output of the Resource.  (5) Resources capable of FFR providing RRS must provide a telemetered output signal, including breaker status and status of the frequency detection device.  (6) Each QSE shall ensure that each Resource is able to meet the Resource’s obligations to provide the RRS award. Each Resource providing RRS must meet additional technical requirements specified in this Section.  (7) Generation Resources offering to provide RRS shall have their Governors in service.  (8) Generation Resources and Resources capable of FFR providing RRS shall have a Governor droop setting that is no greater than 5.0%.  (9) Resources may be provisionally qualified by ERCOT to provide RRS for 90 days. Within the 90-day provisional window, a Resource must successfully complete one of the Governor tests identified in the Nodal Operating Guide Section 8, Attachment C, Turbine Governor Speed Tests, before being declared fully qualified to provide RRS.  (10) For Resources providing RRS and available for dispatch by SCED, the maximum quantity of RRS that a Resource is qualified to provide is limited to the amount of RRS that can be sustained by the Resource for at least 15 minutes. For all other Resources excluding non-CLRs providing FFR, the maximum quantity of RRS that a Resource is qualified to provide is limited to the amount of RRS that can be sustained by the Resource for at least one hour. The maximum quantity of FFR that any non-CLR qualified to provide FFR is limited to the amount of FFR that can be sustained by the Resource for at least 15 minutes.  (11) A qualification test for each Resource to provide RRS is conducted during a continuous eight-hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE. ERCOT shall administer the following test requirements:  (a) At any time during the window, which is selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE that it is to provide an amount of RRS from its Resource to be qualified equal to the amount for which the QSE is requesting qualification. The QSE shall acknowledge the start of the test.  (b) For Generation Resources desiring qualification to provide RRS, ERCOT shall send a signal to the Resource’s QSE to deploy RRS indicating the MW amount. ERCOT shall monitor the QSE’s telemetry of the Resource’s Ancillary Service Schedule for an update within 15 seconds. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.2, Responsive Reserve Service Energy Deployment Criteria. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource’s qualification to provide RRS.  (c) For CLRs desiring qualification to provide RRS, ERCOT shall send a signal to the Resource’s QSE to deploy RRS indicating the MW amount. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.2. ERCOT shall evaluate the response of the CLR given the current operating conditions of the system and determine the CLR’s qualification to provide RRS.  (d) For Load Resources, excluding CLRs, desiring qualification to provide RRS, ERCOT shall deploy RRS indicating the MW amount. ERCOT shall measure the test Resource’s response as described under Section 8.1.1.4.2.  (e) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing RRS and shall provide a copy of the certificate to the QSE and the Resource Entity. |

**16.11.4.1 Determination of Total Potential Exposure for a Counter-Party**

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

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

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

(2) For all Counter-Parties:

TPEA = Max [0, MCE, Max [0, ((1-TOA) \* EAL *q* + TOA \* EAL *t* +EAL *a*)]] + PUL

TPES = Max [0, FCE *a*] + IA

The above variables are defined as follows:

| **Variable** | **Unit** | **Description** |
| --- | --- | --- |
| EAL *q* | $ | *Estimated Aggregate Liability for all QSEs that represents Load or generation*—EAL for all QSEs represented by the Counter-Party if at least one QSE represented by the Counter-Party represents either Load or generation. |
| EAL *t* | $ | *Estimated Aggregate Liability for all QSEs* —EAL for all QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation. |
| EAL *a* | $ | *Estimated Aggregate Liability for all CRR Account Holders*—EAL for all CRR Account Holders represented by the Counter-Party. |
| PUL | $ | *Potential Uplift*—Potential uplift to the Counter-Party, to the extent and in the proportion that the Counter-Party represents Entities to which an uplift of a short payment will be made pursuant to Section 9.19, Partial Payments by Invoice Recipients. It is calculated as the sum of: (a) Amounts expected to be uplifted within one year of the date of the calculation; and (b) the lesser of: (i) 25% of amounts expected to be uplifted beyond one year of the date of the calculation; or (ii) five years’ worth of uplift charges. |
| FCE *a* | $ | *Future Credit Exposure for all CRR Account Holders*—FCE for all CRR Account Holders represented by the Counter-Party. |
| MCE | $ | *Minimum Current Exposure*—For each Counter-Party, ERCOT shall determine a Minimum Current Exposure (MCE) as follows:  MCE = Max[RFAF \* MAF \* Max[{**[**L *i, od, p* \* RTSPP *i, od, p*]/*n*}, {**[[[**L *i, od, p* \* *T2***-** G *i, od, p* \* (1-*NUCADJ*) \* *T3*] \* RTSPP *i, od, p*] + [RTQQNET *i, od, p*\* *T5*]]**/***n*},  {**[**G *i, od, p* \* *NUCADJ* \* *T1* \* RTSPP *i, od, p***]/**n},  {DARTNET*i, od, p* \* *T4*/*n*}],  MAF \* IMCE]  RTQQNET *i, od, p* = Max**[(**RTQQES *i, od, p, c -*RTQQEP *i, od, p, c*), *BTCF* \* (RTQQES *i, od, p, c* – RTQQEP *i, od, p, c*)] \* RTSPP *i, od, p*  DARTNET *i, od, p*  = DAM EOO Cleared *i, od, p* \* DART *i, od, p*+ DAM TPO Cleared *i, od, p* \* DART *i, od, p* + DAM PTP Cleared *i, od, p* \* DARTPTP *i, od, p*– DAM EOB Cleared *i, od, p* \* DART *i, od, p*  Where:  G *i, od, p* = *Total Metered Generation at all Resource Nodes* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  L *i, od, p* = *Total Adjusted Metered Load (AML) at all Load Zones* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  MAF = *Market Adjustment Factor*—Used to provide for the potential for overall price increases based on changes to ERCOT market rules or market conditions. This factor shall not be set below 100%. Revisions to this factor will be recommended by the Technical Advisory Committee (TAC) and the ERCOT Finance and Audit (F&A) Committee, and approved by the ERCOT Board. Such revisions shall be implemented on the 45th calendar day following ERCOT Board approval unless otherwise directed by the ERCOT Board.  *NUCADJ*= *Net Unit Contingent Adjustment*—To allow for situations where a generator may unintentionally or intentionally meet its requirement from the Real-Time Market (RTM)  RTQQNET *i, od, p* = *Net QSE-to-QSE Energy Trades* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  RTQQES *i, od, p, c* = *QSE Energy Trades* for which the Counter-Party is the seller for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*  RTQQEP *i, od, p, c* = *QSE Energy Trades* for which the Counter-Party is the buyer for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*  *BTCF* = *Bilateral Trades Credit Factor*  RTSPP *i, od, p* = *Real-Time Settlement Point Price* for interval *i* for Operating Day *od* at Settlement Point *p*  DARTNET *i, od, p* = *Net DAM activities* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  DART *i, od, p* = *Day-Ahead - Real-Time Spread* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM EOB Cleared*i, od, p* = *DAM Energy Only Bids Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM EOO Cleared *i, od, p* = *DAM Energy Only Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM TPO Cleared *i, od, p* = *DAM Three-Part Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM PTP Cleared *i, od, p* = *DAM Point-to-Point (PTP) Obligations Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DARTPTP *i, od, p* = *Day-Ahead - Real-Time Spread* for value of PTP Obligation for interval *i* for Operating Day *od* at Settlement Point *p*  *c* = Bilateral Counter-Party  *cif = Cap Interval Factor* - Represents the historic largest percentage of System-Wide Offer Cap (SWCAP) intervals during a calendar day  *e* = Most recent *n* Operating Days for which RTM Initial Settlement Statements are available  *i* = Settlement Interval  *n* = Days used for averaging  *nm =* Notional Multiplier  *od* = Operating Day  *p* = A Settlement Point |
| |  |  |  |  | | --- | --- | --- | --- | | ***[NPRR1013 and NPRR1188: Replace applicable portions of the variable “MCE” above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1013; or upon system implementation for NPRR1188:]***   |  |  |  | | --- | --- | --- | | MCE | $ | *Minimum Current Exposure*—For each Counter-Party, ERCOT shall determine a Minimum Current Exposure (MCE) as follows:  MCE = Max[RFAF \* MAF \* Max[{**[**L *i, od, p* \* RTSPP *i, od, p*]/*n*}, {**[[[**L *i, od, p* \* *T2***-** G *i, od, p* \* (1-*NUCADJ*) \* *T3*] \* RTSPP *i, od, p*] + [RTQQNET *i, od, p*\* *T5*]]**/***n*},  {**[**G *i, od, p* \* *NUCADJ* \* *T1* \* RTSPP *i, od, p***]/**n},  {{DARTNET*i, od, p* \* *T4*/*n*} {DARTASONET *i, od, c \* T4/n*}}],  MAF \* IMCE]  RTQQNET *i, od, p* = Max**[(**RTQQES *i, od, p, c -*RTQQEP *i, od, p, c*), *BTCF* \* (RTQQES *i, od, p, c* – RTQQEP *i, od, p, c*)] \* RTSPP *i, od, p*  DARTNET *i, od, p*  = DAM EOO Cleared *i, od, p* \* DART *i, od, p*+ DAM TPO Cleared *i, od, p* \* DART *i, od, p* + DAM PTP Cleared *i, od, p* \* DARTPTP *i, od, p*– DAM EOB Cleared *i, od, p* \* DART *i, od, p*  DARTASONET *i, od* = DAM ASOO Cleared *i, od* \* DARTMCPC *i, od*  Where:  G *i, od, p* = *Total Net Metered Generation at all Resource Nodes,* *including Wholesale Storage Load (WSL) and Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs),* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  L *i, od, p* = *Total Adjusted Metered Load (AML) at all Load Zones,* *excluding CLR Load of CLRs that are not ALRs,* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  MAF = *Market Adjustment Factor*—Used to provide for the potential for overall price increases based on changes to ERCOT market rules or market conditions. This factor shall not be set below 100%. Revisions to this factor will be recommended by the Technical Advisory Committee (TAC) and the ERCOT Finance and Audit (F&A) Committee, and approved by the ERCOT Board. Such revisions shall be implemented on the 45th calendar day following ERCOT Board approval unless otherwise directed by the ERCOT Board.  *NUCADJ*= *Net Unit Contingent Adjustment*—To allow for situations where a generator may unintentionally or intentionally meet its requirement from the Real-Time Market (RTM)  RTQQNET *i, od, p* = *Net QSE-to-QSE Energy Trades* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  RTQQES *i, od, p, c* = *QSE Energy Trades* for which the Counter-Party is the seller for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*  RTQQEP *i, od, p, c* = *QSE Energy Trades* for which the Counter-Party is the buyer for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*  DARTASONET *i, od* = *Net DAM Ancillary Service Only Activities* for interval *i* for Operating Day *od*  DAM ASOO Cleared *i, od* = DAM Ancillary Service Only Offers Cleared in DAM for interval *i* for Operating Day *od*  DARTMCPC *i, od* = Day-Ahead – Real-Time MCPC Spread for interval *i* for Operating Day *od*  *BTCF* = *Bilateral Trades Credit Factor*  RTSPP *i, od, p* = *Real-Time Settlement Point Price* for interval *i* for Operating Day *od* at Settlement Point *p*  DARTNET *i, od, p* = *Net DAM Activities* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*  DART *i, od, p* = *Day-Ahead - Real-Time Spread* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM EOB Cleared*i, od, p* = *DAM Energy Only Bids and Energy Bid Curves Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM EOO Cleared *i, od, p* = *DAM Energy Only Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM TPO Cleared *i, od, p* = *DAM Three-Part Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DAM PTP Cleared *i, od, p* = *DAM Point-to-Point (PTP) Obligations Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*  DARTPTP *i, od, p* = *Day-Ahead - Real-Time Spread* for value of PTP Obligation for interval *i* for Operating Day *od* at Settlement Point *p*  *c* = Bilateral Counter-Party  *cif = Cap Interval Factor* - Represents the historic largest percentage of Day-Ahead System-Wide Offer Cap (DASWCAP) intervals during a calendar day  *e* = Most recent *n* Operating Days for which RTM Initial Settlement Statements are available  *i* = Settlement Interval  *n* = Days used for averaging  *nm =* Notional Multiplier  *od* = Operating Day  *p* = A Settlement Point | | | | |
| IMCE | $ | *Initial Minimum Current Exposure*  IMCE = TOA \* (DASWCAP \* *nm* \* *cif%*) |
| TOA | None | *Trade-Only Activity*—Counter-Party that does not represent either a Load or a generation QSE. Set to “0” if Counter-Party represents a QSE that has an association with a Load Serving Entity (LSE) or a Resource Entity, or if Counter-Party does not represent any QSE;otherwise set to 1. |
| *q* | None | QSEs represented by Counter-Party. |
| *a* | None | CRR Account Holders represented by Counter-Party. |
| IA | $ | *Independent Amount*—The amount required to be posted as defined in Section 16.16.1, Counter-Party Criteria. |
| RFAF | None | *Real-Time Forward Adjustment Factor*—The adjustment factor for RTM-related forward exposure as defined in Section 16.11.4.3.3, Forward Adjustment Factors. |

The above parameters are defined as follows:

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

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

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

**ERCOT Nodal Protocols**

**Section 22**

**Attachment P: Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints**

**June 1, 2025**

**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.

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| ***[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 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.

|  |
| --- |
| ***[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  Some generating units (Generation Resources and Energy Storage Resources (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 participating in the management of congestion on the constraint. I.e. Generation Resources with Shift Factor above 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.

|  |
| --- |
| ***[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  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.[[1]](#footnote-1)

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 Real-Time System-Wide Offer Cap (RTSWCAP).** 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 RTSWCAP and still produce pricing outcomes that remain within reasonable bounds of expected scarcity pricing outcomes. For example, taking the case above where the shift factor difference of the marginal units is just 2%, a constraint shadow price cap of $100,000/MW would be required to deploy $2,000/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 $2,000/MWh RTSWCAP if the constraint was irresolvable. For example, a node with a shift factor of -50% would have an LMP with a congestion component of $50,000/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 RTSWCAP in some circumstances, even ignoring the impacts of co-optimization of energy and Ancillary Services**. 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 RTSWCAP than hubs or load zones, but it is possible that hub or load zone prices could exceed the RTSWCAP. 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 RTSWCAPs, or even the effective Value of Lost Load (VOLL), 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, 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 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.

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| ***[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  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:

1. The Generation Resource with the lowest absolute value of the negative shift factor impact on the violated constraint (this resource is referred as Generation Resource C in the Shadow Price Cap calculation below); and,
2. The Generation Resource with the highest absolute value of the negative shift factor on the violated constraint (this resource is referred to as Generation Resource D in the designation of the net margin Settlement Point Price described below).

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| ***[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  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:  C.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,  D.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 Generation Resources C and D above, ERCOT shall ignore all Generation Resources that have a shift factor with an absolute value of less than 0.02 impact on the irresolvable constraint.

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| ***[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  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 Generation Resource C, as determined above, divided by the absolute value of its shift factor impact on the constraint or$2000 per MW.

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| ***[NPRR1246: Replace paragraph (F) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***   1. 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 Generation 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.

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| ***[NPRR1246: Replace paragraph (G) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***   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 Generation Resource C and D, as described in item C and D above; and,

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| ***[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***   * 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 Generation 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.

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| ***[NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***   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. |

1. 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).
2. 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.
3. 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.

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| ***[NPRR1268: Replace paragraph (B) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  B. The power balance penalty price 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 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 becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources 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.

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| ***[OBDRR020, NPRR1246, and NPRR1268: 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 Energy Storage Resources (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 $4,052.01/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 these Regulation Ancillary Service Generation Resources.

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 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 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 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 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.

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| ***[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**

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| ***MW Violation*** | ***Penalty Value ($/MWh)*** |
| **< 100,000** | **-250** |

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| ***[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.

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| ***[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.

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| ***[OBDRR020 and NPRR1246: 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.

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| ***[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**

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| 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 |

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| ***[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 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.

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| ***[NPRR1246: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***  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.

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| ***[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.

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| ***[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.

1. 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-1)