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OPEN MEETING COVER SHEET

MEMORANDUM AND PROPOSAL FOR PUBLICATION

MEETING DATE:	August 19, 2021
DATE DELIVERED:	August 18, 2021
AGENDA ITEM NO.:	17
CAPTION:	Project No. 52307 – Review of Rules Adopted by the Independent Organization in Calendar Year 2021
DESCRIPTION:	Discussion and Possible Action

Public Utility Commission of Texas

Memorandum

TO: Chairman Peter Lake
Commissioner Will McAdams
Commissioner Lori Cobos
Commissioner Jimmy Glotfelty

FROM: Rebecca Zerwas, Market Analysis

DATE: August 18, 2021

RE: August 19, 2021 Open Meeting – Item No. 17

Project No. 52307 – *Review of Rules Adopted by the Independent Organization in Calendar Year 2021 (Discussion and possible action)*

Senate Bill (SB) 2 (87th Legislature, Regular Session) requires both the Commission and the Electric Reliability Council of Texas (ERCOT) to establish processes for Commission approval of any rules or protocols adopted under authority delegated from the Commission to the independent organization. Commission Staff will utilize Project No. 52307, *Review of Rules Adopted by the Independent Organization in Calendar Year 2021*, to facilitate this review and approval. The Commission adopted its first order approving a set of ERCOT rules in this project at the July 15, 2021 Open Meeting. Staff continues to work with ERCOT on amendments to the revision request approval process in anticipation of Project No. 52301, *ERCOT Governance and Related Issues*, and a full, formal implementation of SB2.

Before the Commission are 15 rules passed through the stakeholder process by the Technical Advisory Committee (TAC) and Board of Directors (Board). These include Nodal Protocol Revision Requests (NPRRs), a Nodal Operating Guide Revision Request (NOGRR), Planning Guide Revision Requests (PGRRs), Resource Registration Glossary Revision Requests (RRGRRs), Other Binding Document Revision Request (OBDRRs), a System Change Request (SCR), and a Retail Market Guide Revision Request (RMGRR). These matters cannot take effect until they receive approval by the Commission. Commission Staff recommends approval.

Discussion

First, Staff requests consideration of RMGRR165, *Modify ERCOT Pre-Launch Responsibilities in a Mass Transition*, as approved by the Technical Advisory Committee (TAC) at its July 28, 2021 meeting. Included for your review are the TAC Report and ERCOT Impact Analysis. Also included are comments filed by Staff in support of RMGRR165. These documents are intended to provide a comprehensive overview describing the revisions, including ERCOT's market impact statement. Staff recommends approval of RMGRR165 in support of improvements to the communications surrounding the Mass Transition process post Winter Storm Uri, including providing the Office of Public Utility Council information at an earlier stage in the process.

Staff also requests consideration of the following rules as approved by Board at its August 10, 2021 meeting:

- NPRR995, *RTF-6 Create Definition and Terms for Settlement Only Energy Storage*. Staff recommends approval in support of the clarity provided regarding the definition and treatment at ERCOT of a Settlement Only Energy Storage System.

- NPRR1005, *Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)*. Staff recommends approval in support of the distinction created by the separate definitions of POI and POIB along with the resulting clarity provided throughout the protocols.

- NPRR1063, *Dynamic Rating Transparency*. Staff recommends approval in support of the transparency provided to market participants and resulting ability to better assess risk.

- NPRR1073, *Market Entry/Participation by Principals of Counter-Parties with Financial Obligations*. Staff recommends approval in support of the increased authority granted to ERCOT to prevent a Principal of a terminated Market Participant with an unpaid financial obligation to ERCOT from re-entering the ERCOT market by forming a new entity.

- NPRR1078, *Clarification of Potential Uplift.* Staff recommends approval in support of amending the Potential Uplift component of the Total Potential Exposure calculation to ensure more accurate collateralization of Counter-Parties given the pending default uplift related to Uri.

- NPRR1079, *Day-Ahead Market RRS / ECRS 48-Hour Report Clarification*. Staff recommends approval in support of ERCOT's attempt to align reporting requirements with the implementation timelines for ancillary service revisions.

- NPRR1083, *Modification of Uplift Allocation Rules to Address Role of Central Counter-Party Clearinghouses*. Staff recommends approval to ensure that uplift charges are allocated in accordance with Senate Bill (SB) 1580 (87th Legislature, Regular Session), which became effective immediately upon its passage on June 18, 2021.

- NPRR1086, *Recovery, Charges, and Settlement for Operating Losses During an LCAP Effective Period*. Staff recommends approval to ensure clarity is provided regarding ERCOT's implementation of the amendments to 16 TAC § 25.505 adopted by the Commission in Project No. 51871, *Review of the ERCOT Scarcity Pricing Mechanism*, which became effective on July 14, 2021.

- NOGRR210, *Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)*. Staff recommends approval in support of the distinction between POI and POIB established in NPRR1005.

- PGRR089, *Planning Data and Information Updates for Planning Posting*. Staff recommends approval in support of ERCOT's changes to the Market Information System (MIS) data sets to reflect current NERC standards and Protected Information posting needs.

- PGRR091, *FIS Application Completion 60-Day Limit*. Staff recommends approval in support of ERCOT's efforts to require Interconnecting Entities (IEs) to timely complete an application to request a Full Interconnection Study (FIS). ERCOT reports show that, between January 1, 2020 to March 11, 2021, only 78% of FIS requests were completed within 60 days.

- RRGRR025, *Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)*. Staff recommends approval in support of the distinction between POI and POIB established in NPRR1005.

- RRGRR028, *Transformer Impedance Clarifications*. Staff recommends approval to address current deficiencies in the transformer data collection requirements, resulting in increased data transparency and improvements to ERCOT's overall modeling process.

- SCR815, *MarkeTrak Administrative Enhancements*. Staff recommends approval to streamline processes, increase transparency and tracking, and improve communication in the MarkeTrak tool for retail market issue resolution.

Included for your review are the Board Report and ERCOT Impact Analysis for each revision request. Also included are two sets of comments filed by Staff at ERCOT regarding NPRR1086. These documents are intended to provide a comprehensive overview describing each revision, including ERCOT's market impact statement.

Finally, ERCOT has requested approval of an Alignment NOGRR, NOGRR229, *Alignment Changes for September 1, 2021 Nodal Operating Guide – NPRR995*. Alignment NOGRRs are not considered through the stakeholder process. Instead, an Alignment NOGRR allows ERCOT to make modifications to the Operating Guides for the purpose of maintaining duplicate language between the Protocols and the related sections of the Operating Guides.[1] ERCOT must post the Alignment NOGRR and distributed to Reliability and Operations Subcommittee (ROS) within five Business Days of ERCOT Board approval of the related NPRR.[2] NPRR995 was approved by the Board on August 10, 2021 and NOGRR229 was posted the same day. Therefore, Staff recommends approval of NOGRR229 consistent with the recommendation for NPRR995 and has included the NOGRR for your review.

Please find attached a proposed order for your consideration consistent with Staff's recommendation in this memo.

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[1] ERCOT Nodal Operating Guide, Section 1, Overview (May 1, 2021).
[2] *Id.*

PROJECT NO. 52307

REVIEW OF RULES ADOPTED BY THE INDEPENDENT ORGANIZATION IN CALENDAR YEAR 2021	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

PROPOSED ORDER APPROVING ERCOT REVISION REQUESTS

This Order addresses revisions to eight Electric Reliability Council of Texas (ERCOT) Nodal Protocols and revisions to seven Market Guide sections. The Order also addresses one System Change that does not require a revision to the ERCOT Nodal Protocols. The Commission approves the revisions and the accompanying market impact statements.

The ERCOT Technical Advisory Committee approved Retail Market Revision Request (RMGRR) 165, *Modify ERCOT Pre-Launch Responsibilities in a Mass Transition*, at its meeting on July 28, 2021. In addition, the ERCOT board of directors approved Nodal Protocol Revision Request (NPRR) 995, *RTF-6 Create Definition and Terms for Settlement Only Energy Storage*, NPRR 1005, *Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)*, NPRR1063, *Dynamic Rating Transparency*, NPRR1073, *Market Entry/Participation by Principals of Counter-Parties with Financial Obligations*, NPRR1078, *Clarification of Potential Uplift*, NPRR1079, *Day-Ahead Market RRS / ECRS 48-Hour Report Clarification,* NPRR1083, *Modification of Uplift Allocation Rules to Address Role of Central Counter-Party Clearinghouses*, NPRR1086, *Recovery, Charges, and Settlement for Operating Losses During an LCAP Effective Period*, Nodal Operating Guide Revision Request (NOGRR) 210, *Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)*, Planning Guide Revision Request (PGRR) 089, *Planning Data and Information Updates for Planning Posting*, PGRR 091, *FIS Application Completion 60-Day Limit*, Resource Registration Glossary Revision Request (RRGRR) 025 *Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)*, RRGRR 028 *Transformer Impedance Clarifications*, AND System Change Request (SCR) 815, *MarkeTrak Administrative Enhancements*, at its meeting on August 10, 2021. ERCOT is also seeking approval of an Alignment NOGRR, NOGRR229, *Alignment Changes for September 1, 2021 Nodal Operating Guide – NPRR995*. Alignment NOGRRs are not considered for approval through the stakeholder process.

Effective June 8, 2021, rules adopted by ERCOT under delegated authority from the Commission are subject to Commission oversight and review and do not take effect before receiving Commission approval.[1] Further, also effective June 8, ERCOT's process for adopting new protocols or revisions to existing protocols must require that new or revised protocols may not take effect until the Commission approves a market impact statement describing the new or revised protocols.[2]

Commission Staff filed a memorandum on August 18, 2021 related to these revisions in which it recommends that the Commission approve the revisions to the Nodal Protocols and Market Guides. Attached to Commission Staff's memorandum were supporting ERCOT documents, which constitute the market impact analysis.

The Commission finds that these revisions are necessary for the proper functioning of the ERCOT market as demonstrated by the supporting material and the Commission issues the following orders:

1. The Commission approves NPRR 995 and accompanying market impact statement.
2. The Commission approves NPRR 1005 and accompanying market impact statement.
3. The Commission approves NPRR 1063 and accompanying market impact statement.
4. The Commission approves NPRR 1073 and accompanying market impact statement.
5. The Commission approves NPRR 1078 and accompanying market impact statement.
6. The Commission approves NPRR 1079 and accompanying market impact statement.
7. The Commission approves NPRR 1083 and accompanying market impact statement.
8. The Commission approves NPRR 1086 and accompanying market impact statement.
9. The Commission approves NOGRR 210 and accompanying market impact statement.

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[1] PURA § 39.151(d); *see also*, *id.* § 39.151(g-1) ERCOT's protocols must be approved by the commission.

[2] PURA § 39.151(g-6).

10. The Commission approves NOGRR 229 and accompanying market impact statement.
11. The Commission approves PGRR 089 and accompanying market impact statement.
12. The Commission approves PGRR 091 and accompanying market impact statement.
13. The Commission approves RMGRR 165 and accompanying market impact statement.
14. The Commission approves RRGRR 025 and accompanying market impact statement.
15. The Commission approves RRGRR 028 and accompanying market impact statement.
16. The Commission approves SCR 815 and accompanying market impact statement.

Signed at Austin, Texas the ______ day of August 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

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PETER M. LAKE, CHAIRMAN

____

WILL MCADAMS, COMMISSIONER

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LORI COBOS, COMMISSIONER

____

JIMMY GLOTFELTY, COMMISSIONER

Board Report

NPRR Number	**995**	**NPRR Title**	**RTF-6 Create Definition and Terms for Settlement Only Energy Storage**
Date of Decision	August 10, 2021		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2025; Rank – 4500		
Nodal Protocol Sections Requiring Revision	1.2, Functions of ERCOT 1.3.1.1, Items Considered Protected Information 1.6.5, Interconnection of New or Existing Generation 2.1, Definitions 2.2, Acronyms and Abbreviations 3.1.6.9, Withdrawal of Approval or Acceptance and Rescheduling of Approved or Accepted Planned Outages of Resource Facilities 3.7, Resource Parameters 3.8.7, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) 3.10.1, Time Line for Network Operations Model Changes 3.10.6, QSE and Resource Entity Responsibilities 3.10.7.2, Modeling of Resources and Transmission Loads 3.14.4.1, Overview and Description of MRAs 6.3.2, Activities for Real-Time Operations 6.5.5.2, Operational Data Requirements 6.5.9.4.2, EEA Levels 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG) 6.6.10, Real-Time Revenue Neutrality Allocation 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria 8.5.1.1, Governor in Service 8.5.1.2, Reporting 8.5.2, Primary Frequency Response Measurements 8.5.2.1, ERCOT Required Primary Frequency Response 9.5.3, Real-Time Market Settlement Charge Types 9.17.1, Billing Determinant Data Elements 9.19.1, Default Uplift Invoices 10.1, Overview 10.2.2, TSP and DSP Metered Entities 10.2.3, ERCOT-Polled Settlement Meters		

	10.2.3.1, Entity EPS Responsibilities 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values 10.2.4.1, Responsibilities for Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters 10.9.1, ERCOT-Polled Settlement Meters 11.1.6, ERCOT Polled Settlement Meter Netting 16.5, Registration of a Resource Entity 16.5.1.2, Waiver for Federal Hydroelectric Facilities 16.11.4.3.2, Real-Time Liability Estimate 22 Attachment L, Declaration of Private Use Network Net Generation Capacity Availability 23 Form I, Resource Entity Application for Registration
Related Documents Requiring Revision/Related Revision Requests	NOGRR229, Alignment Changes for September 1, 2021 Nodal Operating Guide – NPRR995 RRGRR031, Related to NPRR995, RTF-6 Create Definition and Terms for Settlement Only Energy Storage
Revision Description	This Nodal Protocol Revision Request (NPRR) accomplishes objectives of the Resource Definition Task Force (RTF) undertaken at the direction of the Protocol Revision Subcommittee (PRS). Specifically, this NPRR: • Provides a definition for the term Settlement Only Energy Storage System (SOESS) and further defines them as transmission-connected or distribution-connected; • Relocates the definition for Settlement Only Generator (SOG) from underneath Resource to stand alone as its own unrelated term; and • Incorporates the relevant SOESS terms into the Market Information System (MIS) reporting created for SOGs via NPRR917, Nodal Pricing for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs).
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements

Board Report

	☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	This NPRR provides clarity as to how SOESS will be treated within the ERCOT market.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR995 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
PRS Decision	On 2/13/20, PRS unanimously voted to table NPRR995. All Market Segments participated in the vote. On 11/11/20, PRS unanimously voted via roll call to recommend approval of NPRR995 as amended by the 10/28/20 ERCOT comments. All Market Segments participated in the vote. On 12/10/20, PRS unanimously voted via roll call to table NPRR995. All Market Segments participated in the vote. On 1/14/21, PRS voted via roll call to table NPRR995. There was one abstention from the Independent Power Marketer (IPM) (Morgan Stanley) Market Segment. All Market Segments participated in the vote. On 6/10/21, PRS unanimously voted via roll call to endorse and forward to TAC the 1/14/21 PRS Report as amended by the 5/26/21 ERCOT comments and the Impact Analysis for NPRR995 with a recommended priority of 2025 and rank of 4500. All Market Segments participated in the vote.
Summary of PRS Discussion	On 2/13/20, the sponsor reviewed the intent of NPRR995, and participants expressed a desire to table NPRR995 to allow for further review of energy storage issues within other stakeholder forums, including the Battery Energy Storage Task Force (BESTF), RTF, and upcoming Distribution Generation Resource (DGR) workshop(s). On 11/11/20, there was no discussion. On 12/10/20, participants noted the 12/7/20 ERCOT comments requesting an additional month to develop the Impact Analysis for NPRR995.

	On 1/14/21, participants reviewed the Impact Analysis for NPRR995; discussed the 1/12/21 ERCOT comments noting potential impacts to the Passport schedule from NPRR995; and requested a workshop to discuss NPRR995 and related NPRRs which are not currently within the scope of Passport, but cover issues which may need to be addressed prior to Passport implementation. On 6/10/21, participants reviewed the 5/11/21 ERCOT comments, the 5/26/21 ERCOT comments, and the Impact Analysis; and discussed the appropriate priority and rank for NPRR995. Given the relatively high cost of the Impact Analysis, the relatively low level of SOESS MWs currently on the grid, and the expectation that NPRR995 would not be implemented until after the Real-Time Co-Optimization (RTC) project, participants strongly agreed with the 5/11/21 ERCOT comments that a cost-benefit analysis should be performed prior to initiating the project to implement NPRR995.
TAC Decision	On 6/23/21, TAC unanimously voted via roll call to recommend approval of NPRR995 as recommended by PRS in the 6/10/21 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/23/21, participants acknowledged the related Resource Registration Glossary Revision Request (RRGRR) 031, Related to NPRR995, RTF-6 Create Definition and Terms for Settlement Only Energy Storage, will be considered at a future TAC meeting.
ERCOT Opinion	ERCOT supports approval of NPRR995.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR995 and believes the market impact for NPRR995 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.
Board Decision	On 8/10/21, the ERCOT Board recommended approval of NPRR995 as recommended by TAC in the 6/23/21 TAC Report.

Sponsor	
Name	Bob Wittmeyer
E-mail Address	Bwittmeyer@longhornpower.com
Company	Longhorn Power on behalf of Broad Reach Power
Phone Number	512-762-8895
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Board Report

Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
E-Mail Address	cory.phillips@ercot.com
Phone Number	512-248-6464

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

ERCOT 051121	Recommended implementation of NPRR995 after the Energy Management System (EMS) Upgrade and RTC projects; acknowledged the risk of the Impact Analysis growing stale in the interim; and recommended conducting a cost-benefit analysis prior to implementation to ensure sufficient MWs of SOESS exist on the ERCOT System to justify the implementation costs
ERCOT 052621	Provided additional redlines to address baseline Protocol changes

Market Rules Notes

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

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

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

- NPRR967, Remove the 10 MW Limit from the Definition of Limited Duration Resource (LDR) (incorporated 3/1/20)
- NPRR973, Add Definitions for Generator Step-Up and Main Power Transformer (incorporated 9/1/20)
- NPRR986, BESTF-2 Energy Storage Resource Energy Offer Curves, Pricing, Dispatch, and Mitigation (unboxed 4/2/21)
- NPRR990, Relocation of Combined Cycle Train to Resource Attribute (incorporated 9/1/20)
- NPRR1000, Elimination of Dynamically Scheduled Resources (incorporated 9/1/20)
- NPRR1013, RTC – NP 1, 2, 16, and 25: Overview, Definitions and Acronyms, Registration and Qualification of Market Participants, and Market Suspension and Restart (incorporated 1/1/21)
- NPRR1016, Clarify Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) (incorporated 9/1/20)

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

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

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

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

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

- NPRR902, ERCOT Critical Energy Infrastructure Information (unboxed 6/1/21)
  - Section 1.3.1.1
- NPRR945, Net Metering Requirements (incorporated 1/1/21)
  - Section 10.3.2.3
- NPRR979, Incorporate State Estimator Standards and Telemetry Standards into Protocols (incorporated 7/1/21)
  - Section 3.10.6
- NPRR986, BESTF-2 Energy Storage Resource Energy Offer Curves, Pricing, Dispatch, and Mitigation (incorporated 4/2/21)
  - Section 6.6.3.2
- NPRR998, ERS Deployment and Recall Messages (unboxed 4/2/21)
  - Section 6.5.9.4.2
- NPRR1000, Elimination of Dynamically Scheduled Resources (incorporated 9/1/20)
  - Section 6.3.2
- NPRR1006, Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data (incorporated 7/1/20)
  - Section 6.3.2
- NPRR1007, RTC – NP 3: Management Activities for the ERCOT System (incorporated 1/1/21)
  - Section 3.14.4.1
- NPRR1010, RTC – NP 6: Adjustment Period and Real-Time Operations (incorporated 1/1/21)
  - Section 6.3.2
  - Section 6.5.5.2
  - Section 6.5.9.4.2
  - Section 6.6.3.9
- NPRR1011, RTC – NP 8: Performance Monitoring (incorporated 1/1/21)
  - Section 8.1.1.4.2
  - Section 8.5.1.1
- NPRR1012, RTC – NP 9: Settlement and Billing (incorporated 1/1/21)

  - Section 9.5.3
  - Section 9.19.1

- NPRR1013, RTC – NP 1, 2, 16, and 25: Overview, Definitions and Acronyms, Registration and Qualification of Market Participants, and Market Suspension and Restart (incorporated 1/1/21)
  - Section 1.3.1.1
  - Section 16.11.4.3.2

- NPRR1014, BESTF-4 Energy Storage Resource Single Model (incorporated 1/1/21)
  - Section 6.5.5.2

- NPRR1020, Allow Some Integrated Energy Storage Designs to Calculate Internal Loads (unboxed 3/15/21)
  - Section 10.2.3.1
  - Section 10.2.4
  - Section 10.2.4.1
  - Section 10.9.1
  - Section 11.1.6

- NPRR1029, BESTF-6 DC-Coupled Resources (incorporated 1/1/21)
  - Section 6.5.5.2

- NPRR1035, DC Tie Schedules Protected Information Expiry and Posting (incorporated 10/14/20)
  - Section 1.3.1.1

- NPRR1039, Replace the Term MIS Public Area with ERCOT Website (incorporated 1/1/21)
  - Section 1.2
  - Section 3.1.6.9
  - Section 3.10.1
  - Section 6.3.2
  - Section 6.5.9.4.2
  - Section 8.5.2
  - Section 9.17.1
  - Section 10.2.2

- NPRR1041, Adjust Expiration of Protected Information Status for Wholesale Storage Load (WSL) Data (incorporated 1/1/21)
  - Section 1.3.1.1

- NPRR1043, Clarification of NPRR986 Language Related to Wholesale Storage Load (unboxed 4/2/21)
  - Section 6.6.3.2
  - Section 10.2.3
  - Section 11.1.6

- NPRR1047, Consolidate Greybox re NPRR973 and NPRR1016 (incorporated 1/1/21)

  - Section 3.10.7.2

- NPRR1052, Load Zone Pricing for Settlement Only Storage Prior to NPRR995 Implementation (incorporated 3/1/21)
  - Section 6.6.3.2
  - Section 6.6.3.9
  - Section 9.19.1
  - Section 16.5
- NPRR1054, Removal of Oklaunion Exemption Language (incorporated 3/1/21)
  - Section 6.6.10
  - Section 9.5.3
  - Section 16.11.4.3.2
- NPRR1062, Modify IDR Meter Requirement and Eliminate IDR Meter Requirement Report (incorporated 7/1/21)
  - Section 10.2.2
- NPRR1065, Implementation Adjustment for NPRR917 (incorporated 5/1/21)
  - Section 6.6.3.9
  - Section 9.19.1
- NPRR1066, Interconnection of Existing Generation Owned by a Municipally Owned Utility (MOU) or Electric Cooperative (EC) Transferring Load into the ERCOT System (incorporated 5/1/21)
  - Section 1.6.5
- NPRR1074, “mp” Definition Revision (incorporated 6/9/21)
  - Section 9.19.1

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

- NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)
  - Section 3.10.7.2
  - Section 10.3.2.3
- NPRR1067, Market Entry Qualifications, Continued Participation Requirements, and Credit Risk Assessment
  - Section 1.3.1.1
- NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs
  - Section 6.5.5.2
- NPRR1084, Improvements to Reporting of Resource Outages and Derates
  - Section 1.3.1.1
- NPRR1090, ERS Winter Storm Uri Lessons Learned Changes and Other ERS Items
  - Section 6.5.9.4.2

Proposed Protocol Language Revision

1.2 Functions of ERCOT

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

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

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

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

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

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

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

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

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

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

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

[NPRR857: Replace paragraph (7) above with the following upon system implementation:]

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

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

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

1.3.1.1 Items Considered Protected Information

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(p) Credit limits identifiable to a specific QSE;

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

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

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

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

[NPRR857: Replace item (t) above with the following upon system implementation:]

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

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

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

(i) PUCT Substantive Rules on performance measure reporting;

(ii) These Protocols or Other Binding Documents; or

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

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

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

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

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

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

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

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

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

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

[NPRR829: Replace paragraph (ee) above with the following upon system implementation:]

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

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

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

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

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

1.6.5 Interconnection of New or Existing Generation

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

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

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

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

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

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

(b) The generation unit has not undergone a modification pursuant to paragraph (1)(b) of Planning Guide Section 5.1.1, Applicability, subsequent to the specified date from paragraph (3) above;

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

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

2.1 DEFINITIONS

Generation Entity

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

Initial Energization

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

Initial Synchronization

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

Interconnecting Entity (IE)

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

Must-Run Alternative (MRA)

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

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

Must-Run Alternative (MRA)

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

Generation Resource MRA

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

Other Generation MRA

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

Demand Response MRA

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

Weather-Sensitive MRA

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

Non-WSL Settlement Only Charging Load

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

Primary Frequency Response

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

[NPRR989: Replace the above definition "Primary Frequency Response" with the following upon system implementation:]

Primary Frequency Response

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

Resource

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

Energy Storage Resource (ESR)

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

[NPRR1029: Insert the following definition "DC-Coupled Resource upon system implementation:]

DC-Coupled Resource

A type of Energy Storage Resource (ESR) in which an Energy Storage System (ESS) is combined with wind and/or solar generation in the same modeled generation station and interconnected at the same Point of Interconnection (POI), and where these technologies are interconnected within the site using direct current (DC) equipment. The combined technologies are then connected to the ERCOT System using the same direct current-to-alternating current (DC-to-AC) inverter(s). To be classified as a DC-Coupled Resource, the generator(s) and ESS(s) at a site must meet the following conditions:

(1) The ESS component of the Resource must have a nameplate rating of at least ten MW and ten MWh, or the MW rating must equal or exceed 50% of the nameplate MW rating of the inverter; and

(2) All intermittent renewable generators must meet the conditions for aggregation stated in paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, except to the extent any such condition requires the generator to be a Resource.

[NPRR1016: Insert the following definition "Distribution Energy Storage Resource (DESR)" upon system implementation:]

Distribution Energy Storage Resource (DESR)

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

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

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

Generation Resource

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

Distribution Generation Resource (DGR)

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

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

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

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

[NPRR1016: Replace the definition "Distribution Generation Resource (DGR)" above with the following upon system implementation:]

Distribution Generation Resource (DGR)

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

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

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

Transmission Generation Resource (TGR)

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

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

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

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

[NPRR1016: Replace the definition "Transmission Generation Resource (TGR)" above with the following upon system implementation:]

Transmission Generation Resource (TGR)

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

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

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

Load Resource

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

Aggregate Load Resource (ALR)

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

Controllable Load Resource

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

Resource Attribute

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

Aggregate Generation Resource (AGR)

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

[NPRR973: Replace the definition "Aggregate Generation Resource (AGR)" above with the following upon system implementation of PR106:]

Aggregate Generation Resource (AGR)

A Generation Resource that is an aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (12) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, each of which is less than 20 MW in output, which share identical operational characteristics and are interconnected at the same Point of Interconnection (POI) and located behind the same Main Power Transformer (MPT).

Black Start Resource

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

Combined Cycle Train

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

Decommissioned Generation Resource

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

Dynamically Scheduled Resource (DSR)

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

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

Intermittent Renewable Resource (IRR)

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

Intermittent Renewable Resource (IRR) Group

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

[NPRR1013: Replace the definition "Intermittent Renewable Resource (IRR) Group" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Intermittent Renewable Resource (IRR) Group

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

[NPRR1016: Insert the following definition "Inverter-Based Resource (IBR)" upon system implementation:]

Inverter-Based Resource (IBR)

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

Mothballed Generation Resource

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

Quick Start Generation Resource (QSGR)

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

Split Generation Resource

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

Switchable Generation Resource (SWGR)

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

Resource Entity

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

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

Resource Registration

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

Settlement Only Energy Storage System (SOESS)

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

Settlement Only Distribution Energy Storage System (SODESS)

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

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

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

Settlement Only Transmission Energy Storage System (SOTESS)

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

Settlement Only Generator (SOG)

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

Settlement Only Distribution Generator (SODG)

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

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

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

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

Settlement Only Transmission Generator (SOTG)

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

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

Settlement Only Transmission Self-Generator (SOTSG)

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

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

2.2 ACRONYMS AND ABBREVIATIONS

SODESS	Settlement Only Distribution Energy Storage System
SOESS	Settlement Only Energy Storage System
SOTESS	Settlement Only Transmission Energy Storage System

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[NPRR930: Replace paragraph (ii) above with the following upon system implementation:]

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

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

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

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

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

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

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

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

(a) The Load forecast;

(b) Load forecast vendor selection;

(c) Wind forecast;

(d) Wind forecast vendor selection;

(e) Solar forecast;

(f) Solar forecast vendor selection;

(g) Expected severe weather impacts forecast;

(h) Targeted reserve levels;

(i) DC Tie import forecast;

(j) DC Tie export curtailment forecast;

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

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

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

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

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

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

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

3.7 Resource Parameters

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

[NPRR1002: Replace paragraph (1) above with the following upon system implementation:]

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

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

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

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

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

[NPRR1016: Insert Section 3.8.6 below upon system implementation:]

3.8.6 Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)

(1) As a condition for the interconnection of a DGR or DESR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall provide documentation from the DSP to ERCOT stating that the interconnecting distribution circuit will not be disconnected as part of an Energy Emergency Alert (EEA) Level 3, an under-frequency Load shedding event, or an under-voltage Load shedding event, unless required for DSP local system maintenance or during a DSP local system emergency.

(a) If a DSP subsequently determines that any circuit to which a DGR or DESR is interconnected will need to be disconnected during these Load shedding events, or that a DGR or DESR will need to be moved to a circuit that will be disconnected during these Load shedding events:

(i) The DSP shall promptly notify the designated contact for the DGR or DESR;

(ii) The Resource Entity shall promptly notify ERCOT of this fact via the Resource Registration process; and

(iii) The DGR or DESR will immediately be disqualified from offering to provide any Ancillary Service.

(b) Upon receiving notification from the DSP that the DGR or DESR is no longer subject to disconnection during any of these Load shedding events, and that no known system limitations or changes have occurred that would inhibit the DGR or DESR from complying with Ancillary Service performance requirements, the Resource Entity for the DGR or DESR shall notify ERCOT of this fact via the Resource Registration process and will, at that time, be eligible to offer to provide Ancillary Services if the Resource is otherwise qualified to do so.

(2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or for a proposed conversion of an existing Settlement Only Distribution Energy Storage System (SODESS) to a DESR, the interconnecting DSP will evaluate the proposed conversion and will determine whether it is electrically and operationally feasible. If the interconnecting DSP determines that the conversion is not electrically or operationally feasible, the DSP may disallow the conversion.

(3) The Resource Node for a DGR or DESR shall be fixed at a single Electrical Bus in the ERCOT Network Operations Model.

(a) If a DSP determines that a topology change has altered, or is expected to alter, the electrical path connecting the DGR or DESR to the ERCOT Transmission Grid for a period longer than 60 days:

(i) The DSP shall promptly notify the interconnecting Transmission Service Provider (TSP) and the designated contact for the DGR or DESR, and the interconnecting TSP shall notify ERCOT; and

(ii) The Resource Entity shall submit a change request to ERCOT via the Resource Registration process.

3.10.1 Time Line for Network Operations Model Changes

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

[NPRR857: Replace paragraph (1) above with the following upon system implementation:]

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

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

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

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

Notes:

1. TSP and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.
4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

[NPRR857: Replace paragraph (3) above with the following upon system implementation:]

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

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

Notes:

1.	TSP, DCTO, and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2.	Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
3.	Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.
4.	Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

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

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

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

3.10.6 QSE and Resource Entity Responsibilities

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

(2) QSEs shall ensure availability of telemetry to generation and transmission equipment its Resource Entity owns at ERCOT's request to maintain observability and redundancy

requirements as specified herein, and under Section 3.10.7.5, Telemetry Requirements. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

3.10.7.2 Modeling of Resources and Transmission Loads

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

[NPRR973: Replace paragraph (1) above with the following upon system implementation of PR106:]

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

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

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

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

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

[NPRR1016: Replace paragraph (3) above with the following upon system implementation:]

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

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

[NPRR973 and NPRR1016: Replace applicable portions of paragraph (4) above with the following upon system implementation of PR106 or upon system implementation, respectively:]

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

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

(6) TSPs shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be

one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

[NPRR857: Replace paragraph (6) above with the following upon system implementation:]

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

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

[NPRR857: Replace paragraph (7) above with the following upon system implementation:]

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

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

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

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

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

[NPRR1016: Replace paragraph (11) above with the following upon system implementation:]

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

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

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

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

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

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

(e) Either:

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

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

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

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

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

[NPRR885 and NPRR1007: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

3.14.4 Must-Run Alternative Service

3.14.4.1 Overview and Description of MRAs

(1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.

(2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.

(a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

(b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.

(c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT's acceptance of an offer for a Demand Response

MRA on ERCOT's acceptance of an offer for a co-located Other Generation MRA offer.

(d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.

(3) An MRA may be connected at either transmission or distribution voltage.

(4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT's RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.

(5) Each MRA must provide at least five MW of capacity.

(6) Eligible MRA resources may include:

(a) A proposed Generation Resource that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Proposed Generation Resources must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generation Resource Interconnection or Change Request.

(ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the MRA Contracted Hours.

(b) Proposed capacity additions to existing Generation Resources, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary Generator interconnection requirements with respect to this additional capacity.

(ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.

(c) A proposed or existing generator registered, or proposed to be registered, with ERCOT as a Settlement Only Generator (SOG) or as Distributed Generation (DG). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA's projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.

(d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads.

(e) A proposed or existing Energy Storage System (ESS) registered, or proposed to be registered, with ERCOT as a Settlement Only Energy Storage System (SOESS).

(7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT's discretion during the MRA Contracted Hours.

(a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA's temporal constraints.

(b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather–Sensitive MRA.

(8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.

(9) ERCOT will periodically validate an MRA's telemetry using 15-minute interval meter data.

(10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service. Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.

(11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, Other Generation MRA, or Demand Response MRA).

(12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.

(13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site

during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.

(14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.

(15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.

(16) QSEs must submit the following information for each MRA offer:

(a) The capacity, months and hours offered;

(b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;

(c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;

(d) The MRA Standby Price, represented in dollars per MW per hour;

(e) Required capital expenditure, if any, if the MRA offer is awarded;

(f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;

(g) The ramp period or startup time of the MRA or aggregated MRA;

(h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;

(i) The target availability of the MRA or aggregated MRA; and

(j) Any additional information required by ERCOT within the RFP.

(17) Demand Response MRAs shall not be deployed more than once per Operating Day.

(18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.

(19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource.

6.3.2 Activities for Real-Time Operations

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

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

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
Before the start of each SCED run	Update Output Schedules for DSRs	Validate Output Schedules for DSRs Execute Real-Time Sequence
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy prices
During the Operating Hour	Telemeter the Ancillary Service Resource Responsibility for each Resource Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP with actual Resource Status and limits and Ancillary Service Schedules Communicate Resource Forced Outages to ERCOT Communicate to ERCOT Resource changes to Ancillary Service Resource Responsibility via telemetry in the time window beginning 30 seconds prior to the five-minute clock interval and	Communicate all binding Base Points, Dispatch Instructions, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves, and Real-Time Reserve Price Adders for Off-Line Reserves and LMPs for energy and Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand, total Low Ancillary Service Limit (LASL), total High Ancillary Service Limit (HASL), Real-Time On-Line Reliability Deployment Price

Operating Period	QSE Activities	ERCOT Activities
	ending ten seconds prior to that five-minute clock interval	Adder using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs) Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves and Real-Time Reserve Price Adders for Off-Line Reserves, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total On-Line LASL, total On-Line HASL, Real-Time On-Line Reliability Deployment Price Adder created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective

Operating Period	QSE Activities	ERCOT Activities
		Post on the ERCOT website the projected non-binding LMPs created by each SCED process for each Resource Node, the projected total Real-Time reserve amount for On-Line reserves and Off-Line reserves, the projected Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders, and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, total LASL, total HASL, Real-Time On-Line Reliability Deployment Price Adder and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) Post the Settlement Point Prices for each Settlement Point immediately following the end of each Settlement Interval Post the Real-Time On-Line Reliability Deployment Price, Real-Time Reserve Price for On-Line Reserves and the Real-Time Reserve Price for Off-Line Reserves immediately following the end of each Settlement Interval

Operating Period	QSE Activities	ERCOT Activities
		Post parameters as required by Section 6.4.9, Ancillary Services Capacity During the Adjustment Period and in Real-Time, on the ERCOT website

[NPRR829, NPRR904, NPRR917, NPRR1000, NPRR1006, NPRR1010: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR829, NPRR904, NPRR917, NPRR1000, or NPRR1006; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

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

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy and Ancillary Service prices
During the Operating Hour	Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP and telemetry with actual Resource Status and limits and Ancillary Service capabilities	Communicate all binding Base Points, Updated Desired Set Points (UDSPs), Ancillary Service awards, Dispatch Instructions, LMPs for energy, Real-Time MCPCs for Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Transmission and/or Distribution Service Provider (TDSP) standard offer Load

	Submit and update Ancillary Service Offers Communicate Resource Forced Outages to ERCOT	management MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs). In communicating Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable. Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and Real-Time MCPCs for each Ancillary Service, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points

		and Ancillary Service awards from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs), Settlement Only Distribution Energy Storage Systems (SODESSs), Settlement Only Transmission Generators (SOTGs), and Settlement Only Transmission Energy Storage Systems (SOTESSs). These prices shall include Real-Time Reliability Deployment Price Adders for Energy created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective Post every 15 minutes on the ERCOT website the aggregate net injection from Settlement Only Generators (SOGs) and Settlement Only Energy Storage Systems (SOESSs) that provide Real-Time telemetry to ERCOT, consistent with paragraph (12) of Section 6.5.5.2, Operational Data Requirements. This data shall not be displayed if less than five QSEs or less than 750 megawatts of net injection utilize the option to telemeter Real-Time output for use in the calculation of Real-Time Liability (RTL) as described in Section 16.11.4.3.2, Real-Time Liability Estimate. Post on the ERCOT website the projected non-binding LMPs for each Resource Node and Real-Time MCPCs for each Ancillary Service created by each SCED process and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW

		deployed that are deployed that is added to the Demand, Real-Time Reliability Deployment Price Adder for Energy, Real-Time On-Line Reliability Deployment Price Adders for Ancillary Service, and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points and Ancillary Service awards for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections. In posting Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable. Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) Post on the ERCOT website the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG, SODESS, SOTG, and SOTESS immediately following the end of each Settlement Interval By Settlement Interval, post the 15-minute Real-Time Reliability Deployment Price for Energy, and the 15-minute Real-Time Reliability Deployment Price for Ancillary Service for each of the Ancillary Services.

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

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

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

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

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

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

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

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

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

[NPRR1010: Insert paragraphs (6) and (7) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) After every SCED run, ERCOT shall post to the ERCOT website the total capability of Resources available to provide the following Ancillary Service combinations, based on the Resource telemetry from the QSE and capped by the limits of the Resource, for the most recent SCED execution:

(a) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;

(b) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;

(c) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;

(d) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;

(e) Capacity to provide Reg-Up, RRS, or both, irrespective of whether it is capable of providing ECRS or Non-Spin;

(f) Capacity to provide Reg-Up, RRS, ECRS, or any combination, irrespective of whether it is capable of providing Non-Spin;

(g) Capacity to provide Reg-Up, RRS, ECRS, Non-Spin, or any combination; and

(h) Capacity to provide Reg-Down.

(7) Each week, ERCOT shall post on the ERCOT website the historical SCED-interval data described in paragraph (6) above.

6.5.5.2 Operational Data Requirements

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

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

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

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

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

(d) Net Reactive Power (in MVAr);

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

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

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

(h) Generation Resource breaker and switch status;

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

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

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

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

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

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

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

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

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

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

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

(q) Reg-Up and Reg-Down participation factors represent how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified

Resource(s). The Reg-Up and Reg-Down participation factors for a Resource providing Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) shall be zero; and

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

[NPRR863, NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR863, NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

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

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

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

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

(d) Net Reactive Power (in MVAr);

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

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

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

(h) Generation Resource breaker and switch status;

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

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

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

(j) For Resources with capacity that is not capable of providing Primary Frequency Response (PFR), the current FRC of the Resource;

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

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

(m) LSL;

(n) Configuration identification for Combined Cycle Generation Resources;

(o) For Resources with capacity that is not capable of providing PFR, the high and low limits in MW of the Resource's capacity that is frequency responsive;

(p) For RRS, including any sub-categories of RRS, the physical capability (in MW) of the Resource to provide RRS;

(q) For Ancillary Services other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the physical capability of the Resource to provide that specific type of Ancillary Service;

(r) Five-minute blended Normal Ramp Rates (up and down);

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

(t) The telemetered MW of power augmentation capacity that is not On-Line for Resources that have power augmentation capacity included in HSL.

(3) For each Intermittent Renewable Resource (IRR), the QSE shall set the HSL equal to the current net output capability of the facility. The net output capability should consider the

net real power of the IRR generation equipment, IRR generation equipment availability, weather conditions, and whether the IRR net output is being affected by compliance with a SCED Dispatch Instruction.

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

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

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

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

(c) Load Resource breaker status;

(d) LPC (in MW);

(e) MPC (in MW);

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

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

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

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

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

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

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

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

[NPRR863, NPRR1010, and NPRR1029: Replace applicable portions of paragraph (5) above with the following upon system implementation for NPRR863 or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

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

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

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

(c) Load Resource breaker status;

(d) LPC (in MW);

(e) MPC (in MW);

(f) The Load Resource's Ancillary Service self-provision (in MW) for RRS and/or ECRS provided via under-frequency relay;

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

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

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

(j) Resource Status;

(k) For a Controllable Load Resource providing Non-Spin, the "Scheduled Power Consumption Plus Two Hours," representing the QSE's forecast of the Controllable Load Resource's instantaneous power consumption for a point two hours in the future;

(l) For RRS, including any sub-categories of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(m) For Ancillary Service products other than RRS, a blended Normal Ramp Rate (in MW/min) that reflects the current physical capability of the Resource's ability to provide a particular Ancillary Service product; and

(n) For a Controllable Load Resource, 5-minute blended Normal Ramp Rates (up and down).

[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (6) below upon system implementation and renumber accordingly:]

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

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

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

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

(d) Net Reactive Power (in MVAr);

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

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

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

(h) ESR breaker and switch status;

(i) HSL;

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

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

(l) LSL;

(m) For RRS, including any sub-category of RRS, the current physical capability (in MW) of the Resource to provide RRS;

(n) For Ancillary Services other than RRS, a blended ramp rate (in MW/min) that reflects the current physical capability of the Resource to provide that specific type of Ancillary Service; and

(o) Five-minute blended normal up and down ramp rates;

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

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

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

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

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

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

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

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

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

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

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

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

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

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

(a) Combustion turbine inlet air cooling methods;

(b) Duct firing;

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

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

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

[NPRR1010, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (11) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014 or NPRR1029:]

(11) A QSE representing a Generation Resource other than a Combined Cycle Generation Resource may provide FRC telemetry for the Generation Resource only if the QSE or Resource Entity associated with that Generation Resource has first requested and obtained ERCOT's approval.

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

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

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

(c) State of Charge, in MWh;

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

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

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

[NPRR829: Insert paragraph (14) below upon system implementation:]

(14) A QSE representing a Settlement Only Generator (SOG) that elects to include the net generation of the SOG in the estimate of Real-Time Liability (RTL) shall provide ERCOT Real-Time telemetry of the net generation of the SOG.

[NPRR885: Insert paragraph (15) below upon system implementation:]

(15) A QSE representing a Must-Run Alternative (MRA) shall telemeter the MRA MW currently available (unloaded) and not included in the HSL.

[NPRR1029: Insert paragraph (16) below upon system implementation:]

(16) A QSE representing a DC-Coupled Resource shall provide the following Real-Time telemetry data in addition to that required for other Energy Storage Resources (ESRs):

(a) Gross AC MW production of the intermittent renewable generation component of the DC-Coupled Resource, which includes the portion of the intermittent renewable generation used to charge the Energy Storage System (ESS) and/or serve auxiliary Load on the DC side of the inverter; and

(b) Gross AC MW capability of the intermittent renewable generation component of the DC-Coupled Resource, based on Real-Time conditions.

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

6.5.9.4.2 EEA Levels

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

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

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

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

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

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

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

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

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

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

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

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

[NPRR1010: Insert paragraph (v) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(v) At ERCOT's discretion, manually deploy, through ICCP, available RRS and ECRS capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

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

[NPRR1010: Replace paragraph (i) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(i) Ensure COPs and telemetered HSLs, Normal Ramp Rates, Emergency Ramp Rates, and Ancillary Service capabilities are updated and reflect all Resource delays and limitations; and

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

[NPRR1002: Insert paragraph (iii) below upon system implementation:]

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

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

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

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

(2) ERCOT may declare an EEA Level 2 when the clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT will declare an EEA Level 2 when PRC falls below 1,750 MW and is not projected to be recovered above 1,750 MW

within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

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

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

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

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

[NPRR863: Replace item (iii) above with the following upon system implementation:]

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

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

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

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

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

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

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

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

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

[NPRR863: Replace paragraph (v) above with the following upon system implementation:]

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

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

Hotline VDI, which shall initiate the ten-minute deployment period;

[NPRR863 and NPRR939: Replace applicable portions of paragraph (A) above with the following upon system implementation:]

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

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

[NPRR939: Replace paragraph (B) above with the following upon system implementation:]

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

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

[NPRR863 and NPRR939: Replace applicable portions of paragraph (C) above with the following upon system implementation:]

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

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

[NPRR939 and NPRR1010: Replace applicable portions of paragraph (D) above with the following upon system implementation for NPRR939; and upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

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

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

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

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

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

[NPRR1002: Insert paragraph (a) below upon system implementation and renumber accordingly:]

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

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

(b) In addition to measures associated with EEA Levels 1 and 2, TSPs and DSPs or their agents will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TSPs and DSPs or their agents shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

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

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

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

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

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

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

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

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

(g) Its AML at the Settlement Point excluding Non-WSL ESR Charging Load; plus

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

[NPRR917 and NPRR1052: Replace item (h) above with the following upon system implementation of NPRR917:]

(h) The aggregated generation of its Settlement Only Transmission Self-Generators (SOTSGs) at the Settlement Point. SOTSG sites will be represented as a single unit in the ERCOT Settlement system.

(i) The aggregated generation of its Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that have elected to retain Load Zone pricing in accordance with Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS). SODG, SOTG, SODESS and SOTESS sites will be represented as a single unit in the ERCOT Settlement system.

(j) The aggregated generation of its Energy Storage System (ESS) SODGs and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SODG or SOTG nameplate capacity, as confirmed by an affidavit submitted by the Resource Entity for the site. SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.

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

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

[NPRR917: Replace the formula "RTEIAMT $_{q,p}$" above with the following upon system implementation:]

$$\textbf{RTEIAMT}_{q,p} = (-1) * \{[\textbf{RTSPP}_p * [(\textbf{SSSK}_{q,p} * ¼) + (\textbf{DAEP}_{q,p} * ¼) + (\textbf{RTQQEP}_{q,p} * ¼) – (\textbf{SSSR}_{q,p} * ¼) – (\textbf{DAES}_{q,p} * ¼) – (\textbf{RTQQES}_{q,p} * ¼)]] + [\textbf{RTSPPEW}_p * (\textbf{RTMGSOGZ}_{q,p} – (\textbf{RTAML}_{q,p} – \textbf{RTAMLESRNW}_{q,p} – \textbf{RTAMLNWSOL}_{q,p}))]\}$$

And

$$\textbf{LZIMBAL}_{q,p} = (\textbf{SSSK}_{q,p} * ¼) + (\textbf{DAEP}_{q,p} * ¼) + (\textbf{RTQQEP}_{q,p} * ¼) – (\textbf{SSSR}_{q,p} * ¼) – (\textbf{DAES}_{q,p} * ¼) – (\textbf{RTQQES}_{q,p} * ¼) – (\textbf{RTAML}_{q,p} – \textbf{RTAMLESRNW}_{q,p}) + \textbf{RTMGNM}_{q,p}$$

[NPRR917: Replace the formula "LZIMBAL $_{q,p}$" above with the following upon system implementation:]

$$\textbf{LZIMBAL}_{q,p} = (\textbf{SSSK}_{q,p} * ¼) + (\textbf{DAEP}_{q,p} * ¼) + (\textbf{RTQQEP}_{q,p} * ¼) – (\textbf{SSSR}_{q,p} * ¼) – (\textbf{DAES}_{q,p} * ¼) – (\textbf{RTQQES}_{q,p} * ¼) – (\textbf{RTAML}_{q,p} – \textbf{RTAMLESRNW}_{q,p} – \textbf{RTAMLNWSOL}_{q,p}) + \textbf{RTMGSOGZ}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Description
RTEIAMT $_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP $_p$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
LZIMBAL $_{q,p}$	MWh	*Load Zone Energy Imbalance per QSE per Settlement Point*—The Load Zone volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.

Variable	Unit	Description
RTSPPEW $_{p}$	\$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the State Estimated Load for the Load Zone of each SCED interval within the 15-minute Settlement Interval.
RTAML $_{q, p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval.
RTAMLESRNW $_{q, p}$	MWh	*Real-Time Adjusted Metered Load for ESR Non-WSL per QSE per Settlement Point*—The sum of the AML for the Non-WSL ESR Charging Load at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.
RTAMLNWSOL $_{q, p}$	MWh	*Real-Time Adjusted Metered Load for Non-WSL Settlement Only Charging Load per QSE per Settlement Point*—The sum of the AML for the Non-WSL Settlement Only Charging Load for the SODESS or SOTESS site that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.
SSSK $_{q, p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
DAEP $_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSR $_{q, p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
DAES $_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
RTMGNM $_{q, p}$	MWh	*Real-Time Metered Generation from Settlement Only Generators per QSE per Settlement Point*—The total Real-Time energy produced by SOGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval.

[NPRR917 and NPRR1052: Replace the variable "RTMGNM $_{q, p}$" above with the following upon system implementation of NPRR917:]

RTMGSOGZ $_{q, p}$	MWh	*Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by SOTSGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for ESS SODGs and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that have opted out of nodal pricing pursuant to Section 6.6.3.9 will also be included in this value.

Variable	Unit	Description
q	none	A QSE.
p	none	A Load Zone Settlement Point.

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

$$\textbf{RTEIAMTQSETOT}_{q} = \sum_{p} \textbf{RTEIAMT}_{q,p}$$

The above variables are defined as follows:

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

[NPRR917, NPRR1010, NPRR1052, and NPRR1065: Insert applicable portions of Section 6.6.3.9 below upon system implementation of NPRR917 for NPRR917, NPRR1052, and NPRR1065; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.3.9 Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS)

(1) The payment or charge to each QSE for energy from an SODG, SOTG, SODESS, or SOTESS shall be based on an identified nodal energy price, RTESOPR, as described in this subsection, with the exception of an SODG or SOTG that has opted out of nodal pricing as described in paragraph (7) below.

(2) For an SODG or an SODESS, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus associated with this mapped Load in the Network Operations Model. For an SOTG or an SOTESS, the price used as the basis for the 15-minute Real-Time price calculation is the time-weighted price at the Electrical Bus as determined by ERCOT in review of the meter location of the SOTG or SOTESS in the Network Operations Model. Load that is not WSL will be included in the Real-Time AML per QSE. Each SODG, SOTG, SODESS, and SOTESS site will be represented as a single unit in the ERCOT Settlement system.

(3) For an SODG, SOTG, SODESS, or SOTESS, the total payment or charge for each 15-minute Settlement Interval shall be calculated as follows:

$\mathbf{MEBSOGNET}_{q,\,gsc} = \mathbf{Max(0,}\ \sum_{b} \mathbf{MEBSOG}_{q,\,gsc,\,b}\mathbf{)}$If $\text{MEBSOGNET}_{q,\,gsc} = 0$ for a 15-minute Settlement Interval, then

The Load is included in the Real-Time AML per QSE, excluding WSL..

Otherwise, when $\text{MEBSOGNET}_{q,\,gsc} > 0$ for a 15-minute Settlement Interval, then

$$\mathbf{RTGSOAMT}_{q,\,gsc} = \mathbf{(-1) * [} \sum_{b} \mathbf{(\ RTESOPR}_{b} \mathbf{* MEBSOG}_{q,\,gsc,\,b}\mathbf{)]}$$

(4) For an SODESS or SOTESS, the total payment or charge for each 15-minute Settlement Interval shall be calculated as follows:

$$\mathbf{RTWSLSOAMT}_{q,\,gsc} = \mathbf{(-1) * [} \sum_{b} \mathbf{(\ RTESOPR}_{b} \mathbf{* WSOL}_{q,\,gsc,\,b}\mathbf{)]}$$

$$\mathbf{RTNWSLSOAMT}_{q,\,gsc} = \mathbf{(-1) * [} \sum_{b} \mathbf{(\ RTESOPR}_{b} \mathbf{* NWSOL}_{q,\,gsc,\,b}\mathbf{)]}$$

(5) The price for the SOTG, SODG, SODESS, or SOTESS is determined as follows:

$$\mathbf{RTESOPR}_{b} = \mathbf{Max\ [-\$251,}\ \sum_{y} \mathbf{((SDWF}_{y} \mathbf{* RTLMP}_{b,\,y}\mathbf{) + RTRDP)]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{SDWF}_{y} * \text{RTRDPA}_{y})$$

$$\text{SDWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTGSOAMT}_{q,\,gsc}$	$	*Real-Time Generation for SODG, SOTG, SODESS, or SOTESS Site Amount*—The total payment or charge for generation to QSE *q* for SODG, SOTG, SODESS, or SOTESS site *gsc* for the 15-minute Settlement Interval.
$\text{RTWSLSOAMT}_{q,\,gsc}$	$	*Real-Time WSL for SODESS or SOTESS Site Amount*—The total payment or charge for WSL to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.

RTNWSLSOAMT $_{q,\ gsc}$	$	*Real-Time Non-WSL for SODESS or SOTESS Site Amount* —The total payment or charge for Non-WSL Settlement Only Charging Load to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.
RTESOPR $_{b}$	$/MWh	*Real-Time Price for the Energy Metered for each SODG, SOTG, SODESS, or SOTESS Site* —The Real-Time price at Electrical Bus *b* for the Settlement Meter for the SODG, SOTG, SODESS, or SOTESS site for the 15-minute Settlement Interval.
MEBSOGNET $_{q,\ gsc}$	MWh	*Net Metered energy at gsc for an SODG, SOTG, SODESS or SOTESS Site* —The net sum for all Settlement Meters for SODG, SOTG. SODESS or SOTESS site *gsc* represented by QSE *q*. A positive value indicates an injection of power to the ERCOT System.
MEBSOG $_{q,\ gsc,\ b}$	MWh	*Metered energy at bus for an SODG, SOTG, SODESS, or SOTESS Site* —The metered energy by the Settlement Meter(s) at Electrical Bus *b* for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by QSE *q* for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy consumed.
WSOL $_{q,\ gsc,\ b}$	MWh	*WSL for an SODESS or SOTESS Site* - The WSL as measured for an SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by QSE *q,* represented as a negative value, for the 15-minute Settlement Interval.
NWSOL $_{q,\ gsc,\ b}$	MWh	*Non-WSL Settlement Only Charging Load for an SODESS or SOTESS Site* - The Non-WSL Settlement Only Charging Load as measured for an SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by QSE *q,* represented as a negative value, for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA $_{y}$	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
SDWF $_{y}$	None	*SCED Duration Weighting Factor per interval*—The weight used in the SODG, SOTG, SODESS, or SOTESS price calculation for the portion of the SCED interval *y* within the Settlement Interval.
RTLMP $_{b,\ y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus *b*, for the SCED interval *y*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y* within the Settlement Interval.
gsc	none	A generation site code.
b	none	An Electrical Bus.
y	None	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

(6) The total net payments and charges to each QSE for energy from SODGs, SOTGs, SODESS, or SOTESS for the 15-minute Settlement Interval is calculated as follows:

$$\text{RTESOAMTQSETOT}_{q} = \sum_{gsc} (\text{RTGSOAMT}_{q,\,gsc} + \text{RTWSLSOAMT}_{q,\,gsc} + \text{RTNWSLSOAMT}_{q,\,gsc})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RTESOAMTQSETOT}_{q}$	$	*Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESSs, or SOTESSs* —The payment or charge to QSE *q* for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval.
$\text{RTGSOAMT}_{q,\,gsc}$	$	*Real-Time Generation for SODG, SOTG, SODESS, or SOTESS Site Amount* —The total payment or charge for generation to QSE *q* for SODG, SOTG, SODESS, or SOTESS site *gsc* for the 15-minute Settlement Interval.
$\text{RTWSLSOAMT}_{q,\,gsc}$	$	*Real-Time WSL for SODESS or SOTESS Site Amount* —The total payment or charge for WSL to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.
$\text{RTNWSLSOAMT}_{q,\,gsc}$	$	*Real-Time Non-WSL for SODESS or SOTESS Site Amount* —The total payment or charge for Non-WSL Settlement Only Charging Load to QSE *q* for the SODESS or SOTESS site *gsc* for the 15-minute Settlement Interval.
q	none	A QSE.
gsc	none	A generation site code.

(7) Notwithstanding anything else in this Section except paragraphs (8) and (9) below, a Resource Entity may opt out of nodal pricing and continue Load Zone Settlement for any SODG or SOTG if, by January 1, 2019, the SODG or SOTG was operational or was subject to a Power Purchase or Tolling Agreement (PPA) or Transmission and/or Distribution Service Provider (TDSP) interconnection agreement, or had an executed agreement with a developer. By December 31, 2019, the Resource Entity must submit a properly completed Section 23, Form N, Pricing Election for Settlement Only Distribution Generators and Settlement Only Transmission Generators. Any SODG or SOTG relying on a PPA or TDSP interconnection agreement or agreement with a developer must also have achieved Initial Synchronization for the full Resource capacity before June 1, 2020 to be eligible to opt out of nodal pricing. A Resource Entity must provide ERCOT documented proof of any PPA, TDSP interconnection agreement, or developer agreement that it relies on as a basis for any election under this paragraph. This election is valid through the earlier of December 31, 2029 or the date on which the election is revoked pursuant to paragraph (10) of this Section. On January 1, 2030, all SODGs and SOTGs will be subject to nodal pricing.

(8) For any SODG or SOTG for which the applicable Resource Entity has elected to opt out of nodal pricing, ERCOT shall settle the output of the SODG or SOTG using the Load Zone Settlement Point Price for the duration of the opt-out period so long as the SODG or SOTG is not physically modified for any purpose, including to increase the capacity of the unit or change the fuel type of the unit, except as necessary for routine maintenance or repairs to address normal wear and tear.

(9) If at any time ERCOT determines that the SODG or SOTG fails to meet the opt-out conditions in paragraph (8) above, ERCOT shall settle the output of the SODG or SOTG

at the applicable nodal price as soon as practicable after providing written notice to the affected Resource Entity.

(10) A Resource Entity that has opted out of nodal pricing for one or more SODGs or SOTGs pursuant to paragraph (7) of this Section may withdraw that election and begin receiving applicable nodal pricing for one or more such generators by submitting a properly completed election form (Section 23, Form N). An election of nodal pricing is irrevocable. ERCOT will effectuate the transition of an SODG or SOTG to nodal pricing in ERCOT Settlement systems as soon as practicable.

6.6.10 Real-Time Revenue Neutrality Allocation

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

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

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

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

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

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

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

[NPRR1054: Delete paragraph (f) above upon system implementation and renumber accordingly.]

[NPRR917: Insert item (g) below upon system implementation and renumber accordingly:]

(g) Real-Time Energy payments or charges under Section 6.6.3.9, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only

Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS);

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

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

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

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

[NPRR917 and NPRR1054: Replace applicable portions of the formula "LARTRNAMT $_q$" above with the following upon system implementation:]

$$\mathbf{LARTRNAMT}_{q} = \mathbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTESOAMTTOT + RTCCAMTTOT + RTOBLAMTTOT / 4 + RTOBLLOAMTTOT / 4) * LRS}_{q}$$

Where:

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

$$\text{RTEIAMTTOT} = \sum_{q} \text{RTEIAMTQSETOT}_{q}$$

Total Real-Time Payment for BLT Resources

$$\text{BLTRAMTTOT} = \sum_{q} \text{BLTRAMTQSETOT}_{q}$$

Total Real-Time Payment for DC Tie Imports

$$\text{RTDCIMPAMTTOT} = \sum_{q} \text{RTDCIMPAMTQSETOT}_{q}$$

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

$$\text{RTDCEXPAMTTOT} = \sum_{q} \text{RTDCEXPAMTQSETOT}_{q}$$

[NPRR1054: Delete the formula "RTDCEXPAMTTOT" above upon system implementation.]

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

$$\text{RTCCAMTTOT} = \sum_{q} \text{RTCCAMTQSETOT}_{q}$$

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

$$\text{RTOBLAMTTOT} = \sum_{q} \text{RTOBLAMTQSETOT}_{q}$$

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

$$\text{RTOBLLOAMTTOT} = \sum_{q} \text{RTOBLLOAMTQSETOT}_{q}$$

[NPRR917: Insert the language below upon system implementation:]

Total Real-Time Payment or Charge for energy from SODGs, SOTGs, SODESSs, or SOTESSs

$$\text{RTESOAMTTOT} = \sum_{q} \text{RTESOAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
LARTRNAMT $_q$	$	*Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*'s share of the total Real-Time revenue neutrality amount, for the 15-minute Settlement Interval.
RTEIAMTTOT $_q$	$	*Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance Service at all Settlement Points (Resource, Load Zone or Hub) for the 15-minute Interval.
BLTRAMTTOT	$	*Block Load Transfer Resource Amount Total*—The total of payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTTOT	$	*Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval.
RTDCEXPAMTTOT	$	*Real-Time DC Export Amount Total*—The summation of charges to all QSEs under the "Oklaunion Exemption" for DC Tie exports for the 15-minute Settlement Interval.
[NPRR1054: Delete the variable "RTDCEXPAMTTOT" above upon system implementation.]		
RTCCAMTTOT	$	*Real-Time Energy Congestion Cost Amount Total*—The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval.
RTOBLAMTTOT	$	*Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval.
RTOBLLOAMTTOT	$	*Real-Time Obligation with Links to an Option Amount Total*—The sum of all payments for PTP Obligations with Links to an Option settled in Real-Time for the hour that includes the 15-minute Settlement Interval.

Variable	Unit	Description
RTEIAMTQSETOT $_q$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE q for Real-Time Energy Imbalance at all Resource Node Settlement Points for the 15-minute Settlement Interval.
RTCCAMTQSETOT $_q$	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE q for its Self-Schedules for the 15-minute Settlement Interval.
BLTRAMTQSETOT $_q$	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE q for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTQSETOT $_q$	$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE q for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
RTDCEXPAMTQSETOT $_q$	$	*Real-Time DC Export Amount QSE Total per QSE*—The total of the charges to QSE q for energy exported from the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
[NPRR1054: Delete the variable "RTDCEXPAMTQSETOT" above upon system implementation.]		
RTOBLAMTQSETOT $_q$	$	*Real-Time Obligation Amount QSE Total per QSE*—The net total payment or charge to QSE q of all its PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time.
RTOBLLOAMTQSETOT $_q$	$	*Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The total payment to QSE q for all of its PTP Obligations with Links to an Option settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.1.
[NPRR917: Insert the variables "RTESOAMTQSETOT $_q$" and "RTESOAMTTOT" below upon system implementation:]		
RTESOAMTQSETOT $_q$	$	*Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESSs, or SOTESSs* —The payment or charge to QSE q for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval.
RTESOAMTTOT	$	*Real-Time Energy Amount Total from all SODGs, SOTGs, SODESSs, or SOTESSs* —The total net payments and charges to all QSEs for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval.
LRS $_q$	none	The LRS calculated for QSE q for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
o	none	A CRR owner.

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

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

[NPRR917 and NPRR1054: Replace applicable portions of the formula "LARTRNAMT $_q$" above with the following upon system implementation:]

$$\textbf{LARTRNAMT}_{q} = \textbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTESOAMTTOT + RTCCAMTTOT + NDRTOBLAMTTOT / 4 + NDRTOPTAMTTOT / 4 + NDRTOPTRAMTTOT / 4 + NDRTOBLRAMTTOT / 4) * LRS}_{q}$$

Where:

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

$$\text{RTEIAMTTOT} = \sum_{q} \text{RTEIAMTQSETOT}_{q}$$

Total Real-Time Payment for BLT Resources

$$\text{BLTRAMTTOT} = \sum_{q} \text{BLTRAMTQSETOT}_{q}$$

Total Real-Time Payment for DC Tie Imports

$$\text{RTDCIMPAMTTOT} = \sum_{q} \text{RTDCIMPAMTQSETOT}_{q}$$

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

$$\text{RTDCEXPAMTTOT} = \sum_{q} \text{RTDCEXPAMTQSETOT}_{q}$$

[NPRR1054: Delete the formula "RTDCEXPAMTTOT" above upon system implementation.]

Total Real-Time Congestion Payment or Charge for Self Schedules

$$\text{RTCCAMTTOT} = \sum_{q} \text{RTCCAMTQSETOT}_{q}$$

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

$$\text{NDRTOBLAMTTOT} = \sum_{o} \text{NDRTOBLAMTOTOT}_{o}$$

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

$$NDRTOPTAMTTOT = \sum_{o} NDRTOPTAMTOTOT_{o}$$

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

$$NDRTOPTRAMTTOT = \sum_{o} NDRTOPTRAMTOTOT_{o}$$

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

$$NDRTOBLRAMTTOT = \sum_{o} NDRTOBLRAMTOTOT_{o}$$

[NPRR917: Insert the language below upon system implementation:]

Total Real-Time Payment or Charge for energy from SODGs, SOTGs, SODESSs, or SOTESSs

$$RTESOAMTTOT = \sum_{q} RTESOAMTQSETOT_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
LARTRNAMT $_{q}$	$	*Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*'s share of the total Real-Time revenue neutrality amount for the 15-minute Settlement Interval.
RTEIAMTTOT	$	*Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance at all Settlement Points (Resource, Load Zone, or Hub) for the 15-minute Interval.
BLTRAMTTOT	$	*Block Load Transfer Resource Amount Total*—The total of the payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTTOT	$	*Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval.
RTDCEXPAMTTOT	$	*Real-Time DC Export Amount Total*—The summation of charges to all QSEs that are under the "Oklaunion Exemption" for DC Tie exports for the 15-minute Settlement Interval.
[NPRR1054: Delete the variable "RTDCEXPAMTTOT" above upon system implementation.]		
RTCCAMTTOT	$	*Real-Time Energy Congestion Cost Amount Total*—The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval.
NDRTOBLAMTTOT	$	*No DAM Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.

Variable	Unit	Description
NDRTOPTAMTTOT	$	*No DAM Real-Time Option Amount Total*—The sum of all payments for PTP Options settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOPTRAMTTOT	$	*No DAM Real-Time Option with Refund Amount Total*—The sum of all payments for PTP Options with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOBLRAMTTOT	$	*No DAM Real-Time Obligation with Refund Amount Total*— The sum of all payments for PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
RTEIAMTQSETOT $_q$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval.
RTCCAMTQSETOT $_q$	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
BLTRAMTQSETOT $_q$	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTQSETOT $_q$	$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
RTDCEXPAMTQSETOT $_q$	$	*Real-Time DC Export Amount QSE Total per QSE*—The total of the charges to QSE *q* for energy exported from the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
[NPRR1054: Delete the variable "RTDCEXPAMTQSETOT $_q$" above upon system implementation.]		
NDRTOBLAMTOTOT $_o$	$	*No DAM Real-Time Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* of all its PTP Obligations settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTAMTOTOT $_o$	$	*No DAM Real-Time Option Amount Owner Total per CRR Owner*—The total payment to CRR owner *o* for all its PTP Options settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTRAMTOTOT $_o$	$	*No DAM Real-Time Option with Refund Amount Owner Total per CRR Owner*—The total payment to Non-Opt-In Entity (NOIE) CRR owner *o* for all its PTP Options with Refund settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOBLRAMTOTOT $_o$	$	*No DAM Real-Time Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* for all its PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.

Variable	Unit	Description
[NPRR917: Insert the variables "RTESOAMTQSETOT $_q$" and "RTESOAMTTOT" below upon system implementation:]		
RTESOAMTQSETOT $_q$	$	*Real-Time Energy Payment or Charge per QSE for SODGs, SOTGs, SODESSs, or SOTESSs*—The payment or charge to QSE *q* for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval.
RTESOAMTTOT	$	*Real-Time Energy Amount Total from all SODGs, SOTGs, SODESSs, or SOTESSs*—The total net payments and charges to all QSEs for Real-Time energy from SODGs, SOTGs, SODESSs, or SOTESSs for the 15-minute Settlement Interval.
LRS $_q$	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2.
q	none	A QSE.
o	none	A CRR Owner.

8.1.1.4.2 Responsive Reserve Energy Deployment Criteria

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

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

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

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

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

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

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

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

(ii) The requested MW deployment.

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

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

(6) A Load Resource providing RRS excluding Controllable Load Resources must return to at least 95% of its Ancillary Service Resource Responsibility for RRS within three hours

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

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

[NPRR863 and NPRR1011: Replace applicable portions of Section 8.1.1.4.2 above with the following upon system implementation for NPRR863; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.4.2 Responsive Reserve Energy Deployment Criteria

(1) Control performance during periods in which RRS has been self-deployed shall be based on the requirements below and failure to meet any one of these requirements may be reported to the Reliability Monitor as non-compliance:

(a) A QSE providing RRS must reserve sufficient Primary Frequency Response capable capacity on each Generation Resource with a RRS award or must reserve sufficient capacity capable of FFR to supply the full amount of RRS awarded to that Resource. The QSE shall not use non-FRC, such as power augmentation capacity on a Generation Resource, to provide RRS.

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

(2) For all Frequency Measurable Events (FMEs), ERCOT shall use the recorded data for each two-second scan rate value of real power output for each Generation Resource, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), Settlement Only Transmission Energy Storage System (SOTESS), Resource capable of FFR providing RRS, and Controllable Load Resource. ERCOT shall use the recorded MW data beginning one minute before the start of the frequency excursion event until ten minutes after the start of the frequency excursion

event. Satisfactory performance for those Resources with an RRS award must be measured by comparing actual Primary Frequency Response to the expected Primary Frequency Response as required in the Operating Guides.

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

(4) For Resources providing FFR, once the FFR is deployed, the Resource must stay deployed for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurs first. A Load Resource that is controlled by a high-set under-frequency relay and is providing FFR may only withdraw energy from the grid after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, or if instructed to do so by ERCOT.

(5) For a Resource providing RRS with a Resource Status of ONSC, once the RRS is deployed, the Resource must maintain the response until recalled by ERCOT.

(6) For a Load Resource that is controlled by a high-set under-frequency relay and is providing RRS, once the RRS is deployed, the Resource must maintain the response to the deployment until recalled by ERCOT.

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

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

(ii) The requested MW deployment.

The QSE's portfolio shall maintain this response until recalled.

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

(9) For a QSE self-providing RRS on Load Resources, excluding Controllable Load Resources that have been deployed for RRS, the QSE may move the self-provided

amount to another Load Resource, while maintaining the deployment instructions on the previously deployed Load Resource, if:

(a) The Load Resource to which the RRS is to be moved is not a Controllable Load Resource and has not been deployed for RRS; and

(b) The self-provided amount of RRS is within the QSE's portfolio.

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

8.5.1.1 Governor in Service

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

[NPRR863 and NPRR989: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) At all times a Generation Resource, Energy Storage Resource (ESR), Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) is On-Line, its Governor must remain in service and be allowed to respond to all changes in system frequency except during startup, shutdown, or testing. A Resource Entity may