Filing Receipt

Filing Date - 2024-12-09 01:31:52 PM

Control Number - 54445

Item Number - 101

PROJECT NO. 54445

REVIEW OF PROTOCOLS ADOPTED BY THE INDEPENDENT ORGANIZATION	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

NOTICE OF RECOMMENDED APPROVAL OF REVISION REQUESTS BY ERCOT BOARD OF DIRECTORS

Effective June 8, 2021, rules adopted by Electric Reliability Council of Texas, Inc. (ERCOT) under delegated authority from the Public Utility Commission of Texas (Commission) are subject to Commission oversight and review and may not take effect before receiving Commission approval.

At its meeting on December 3, 2024, the ERCOT Board of Directors (Board) recommended Commission approval of the following proposed revisions to the ERCOT rules (Revision Requests), (Nodal Protocol Revision Requests (NPRRs), Nodal Operating Guide Revision Request (NOGRR), Other Binding Documents Revision Request (OBDRR) and Planning Guide Revision Requests (PGRRs)):

- NPRR1180, Inclusion of Forecasted Load in Planning Analyses;
- NPRR1239, Access to Market Information;
- NPRR1240, Access to Transmission Planning Information;
- NPRR1245, Additional Clarifying Revisions to Real-Time Co-Optimization;
- NPRR1247, Incorporation of Congestion Cost Savings Test in Economic Evaluation of Transmission Projects;
- NPRR1248, Correction to NPRR1197, Optional Exclusion of Load from Netting at EPS Metering Facilities which Include Resources;
- NPRR1249, Publication of Shift Factors for All Active Transmission Constraints in the RTM;
- NPRR1254, Modeling Deadline for Initial Submission of Resource Registration Data;
- NOGRR266, Related to NPRR1239, Access to Market Information;
- NOGRR267, Related to NPRR1240, Access to Transmission Planning Information;
- OBDRR053, Alignment with NPRR1131, Controllable Load Resource Participation in Non-Spin, and Minor Clean-Ups;

- PGRR107, Related to NPRR1180, Inclusion of Forecasted Load in Planning Analyses; and
- PGRR116, Related to NPRR1240, Access to Transmission Planning Information;

Included for Commission review are the Board Reports—each of which includes an ERCOT Market Impact Statement—and ERCOT Impact Analyses for these Revision Requests.

Dated: December 9, 2024

Respectfully submitted,

/s/ Brandt Rydell

Chad V. Seely
Senior Vice President and General Counsel
Texas Bar No. 24037466
(512) 225-7035 (Phone)
chad.seely@ercot.com

Brandt Rydell
Assistant General Counsel
Texas Bar No. 00798477
(512) 248-3928 (Phone)
brandt.rydell@ercot.com

ERCOT
8000 Metropolis Drive (Building E), Suite 100
Austin, Texas 78744
(512) 225-7079 (Fax)

ATTORNEYS FOR ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.

Board Report

NPRR Number	1180	NPRR Title	Inclusion of Forecasted Load in Planning Analyses
Date of Decision		December 3, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: Not applicable	
Proposed Effective Date		First of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		2.1, Definitions 3.11.4.1, Project Submission 3.11.4.1.1, Project Submissions Based on Unsubstantiated Load (new) 3.11.4.6, Processing of Tier 2 Projects 3.11.4.7, Processing of Tier 1 Projects 3.11.4.9, Regional Planning Group Acceptance and ERCOT Endorsement	
Related Documents Requiring Revision/Related Revision Requests		Planning Guide Revision Request (PGRR) 107, Related to NPRR1180, Inclusion of Forecasted Load in Planning Analyses	
Revision Description		This Nodal Protocol Revision Request (NPRR) revises the Protocols to address recent amendments to P.U.C. SUBST. R. 25.101, Certification Criteria, which became effective on December 20, 2022. Specifically, NPRR1180 incorporates the requirement in P.U.C. SUBST. R. 25.101(b)(3)(A)(ii)(II) for any reliability-driven transmission project review conducted by ERCOT to incorporate the historical load, forecasted load growth, and additional load seeking interconnection, in the ERCOT independent review.	
Reason for Revision		☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience	

Board Report

	☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☒ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	The inclusion of historical load, forecasted load growth, and additional load seeking interconnection in transmission project reviews conducted by ERCOT is required by PUCT Rule for Certificates of Convenience and Necessity (CCNs). Including that information in ERCOT's independent reviews of Regional Planning Group (RPG) projects will help ensure ERCOT's transmission project recommendations support long-term system and Customer needs.
PRS Decision	On 6/14/23, PRS voted unanimously to table NPRR1180 and refer the issue to ROS. All Market Segments participated in the vote. On 9/12/24, PRS voted to recommend approval of NPRR1180 as amended by the 8/28/24 ERCOT comments. There were two abstentions from the Independent Generator (Calpine, Constellation) Market Segment. All Market Segments participated in the vote. On 10/17/24, PRS voted unanimously to endorse and forward to TAC the 9/12/24 PRS Report and 10/16/24 Impact Analysis for NPRR1180. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/14/23, Oncor reviewed NPRR1180 and participants requested further discussion at ROS. On 9/12/24, participants reviewed the 8/28/24 ERCOT comments. On 10/17/24, participants reviewed the 10/16/24 Impact Analysis and 10/16/24 ERCOT comments. Some participants expressed concern the 10/16/24 Impact Analysis is too broad and exceeds the scope of NPRR1180.

Board Report

TAC Decision	On 10/30/24, TAC voted unanimously to table NPRR1180. All Market Segments participated in the vote. On 11/20/24, TAC voted to recommend approval of NPRR1180 as recommended by PRS in the 10/17/24 PRS Report and the 10/28/24 Revised Impact Analysis. There were four abstentions from the Consumer (2) (Residential Consumer, OPUC), Cooperative (GSEC) and Independent Power Marketer (IPM) (SENA) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/30/24, TAC reviewed the 10/28/24 Revised Impact Analysis and participants requested tabling NPRR1180 so it could be considered with PGRR107. Participants raised concerns with the lack of transparency and standardization for incorporating anticipated load into planning studies and discussed paths forward for potential future refinements to address these concerns. On 11/20/24, participants expressed concern that estimated load values used in planning studies may not materialize as predicted and stressed the importance of using quality data to calculate load forecasts so that they are as accurate as possible.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1180 as recommended by TAC in the 11/20/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1180 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The IMM conditionally supports NPRR1180 in concept however the details of the robustness and use of data in developing inputs to the planning analysis are important. IMM support is contingent upon

Board Report

	ERCOT's ability to apply reasonable methods to the data they are provided in order to produce the most accurate forecast for use in planning analysis.
ERCOT Opinion	ERCOT supports approval of NPRR1180.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1180 and believes it appropriately incorporates the requirement in P.U.C. Subst. R.25.101(b)(3)(A)(ii)(II) for any reliability-driven transmission project review conducted by ERCOT to account for historical Load, forecasted Load growth, and additional Load seeking interconnection.

Sponsor	
Name	Martha Henson
E-mail Address	martha.henson@oncor.com
Company	Oncor Electric Delivery Company LLC
Phone Number	214-536-9004
Cell Number	
Market Segment	Investor Owned Utility (IOU)
Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
E-Mail Address	Erin.Wasik-Gutierrez@ercot.com
Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
ROS 070723	Requested PRS continue to table NPRR1180 for further review by the Planning Working Group (PLWG)
AEP Texas and ETT 081523	Supported the inclusion of forecasted Load growth and proposed additional revisions requiring acceptance or endorsement to carry the same weight as it would if a project were justified by other needs

Board Report

ROS 110323	Endorsed NPRR1180 as amended by the 8/15/24 AEP Texas and ETT comments
ERCOT 121323	Revised the 8/15/24 AEP Texas and ETT comments to provide that ERCOT will not issue an endorsement of any project that is proposed by a Transmission Service Provider (TSP) based on Load values that are not supported by interconnection agreements or other quantifiable evidence of Load growth
ERCOT 071524	Revised the 12/13/23 ERCOT comments to ensure that transmission needs identified by ERCOT are based on evidence of Load that meets a minimum threshold of facial credibility
ERCOT 082824	Replaced various instances of the term "Load" with the uncapitalized term "load"
ERCOT 101624	Provided additional detail to support the 10/16/24 Impact Analysis
TCPA 102924	Requested NPRR1180 be tabled so stakeholders can work to develop a more standardized process for qualifying load for inclusion in planning studies
OPUC 111824	Recommended that ERCOT and stakeholders collaborate to more thoroughly validate forecasted load growth before proceeding with this NPRR
Oncor 111824	Indicated Oncor is committed to an effort to create public transparency for the contents of TSP officer letters and encouraged TAC members to support the passage of NPRR1180 and PGRR107
OPUC 111924	Reiterated that a transparent and well-defined approach to including load forecasts in the ERCOT transmission planning process is crucial and recommended ERCOT and stakeholders collaborate to more thoroughly validate forecasted load growth before proceeding with this NPRR

Market Rules Notes

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

- NPRR956, Designation of Providers of Transmission Additions
  - Section 3.11.4.1
  - Section 3.11.4.9

Proposed Protocol Language Revision

Board Report

2.1 DEFINITIONS

Substantiated Load

Load submitted by a TDSP for planning purposes that is substantiated by any of the following:

(a) An executed interconnection or other agreement;

(b) An independent third-party ~~l~~Load forecast that has been deemed credible by ERCOT and that may include ~~l~~Load for which a TDSP has yet to sign an interconnection agreement; or

(c) A letter from a TDSP officer attesting to such ~~l~~Load, which may include ~~l~~Load for which a TDSP has yet to sign an interconnection agreement.

Unsubstantiated Load

Load submitted by a TDSP for planning purposes that is not Substantiated Load.

3.11.4 Regional Planning Group Project Review Process

3.11.4.1 Project Submission

Commented [EWG1]: Please note NPRR956 also proposes revisions to this section.

(1) Any stakeholder may initiate an RPG Project Review through the submission of a document describing the scope of the proposed transmission project to ERCOT. Projects should be submitted with sufficient lead-time to allow the RPG Project Review to be completed prior to the date on which the project must be initiated by the designated TSP.

(2) Stakeholders may submit projects for RPG Project Review within any project Tier. All transmission projects in Tiers 1, 2 and 3 shall be submitted. TSPs are not required to submit Tier 4 projects for RPG Project Review, but shall include any Tier 4 projects in the cases used for development of the Regional Transmission Plan.

(3) All system improvements that are necessary for the project to achieve the system performance improvement, or to correct the system performance deficiency, for which the project is intended should be included into a single project submission.

~~(4) Any relevant historical Load information, or quantifiable evidence supporting the forecasted Load growth and additional Load seeking interconnection in the project area, should be provided with the RPG project submission, if applicable. Confidential information provided by Customers can be incorporated by reference and made available for inspection by ERCOT upon request.~~

(~~5~~4) Facility ratings updates are not considered a project and are not subject to RPG Project Review.

3.11.4.1.1 Project Submissions Based on Unsubstantiated Load

(1) Following the submission of a project by a TSP, if ERCOT determines that the asserted need for a Tier 1, Tier 2, or Tier 3 project is based in part or in whole on Unsubstantiated Load, ERCOT shall notify the submitting TSP and the RPG, and neither ERCOT nor the RPG will conduct any further review of the project.

3.11.4.6 Processing of Tier 2 Projects

(1) ERCOT shall conduct an independent review of a submitted Tier 2 project as follows:

(a) ERCOT's independent review shall consist of studies and analyses necessary for ERCOT to make its assessment of whether the proposed project is needed and whether the proposed project is the preferred solution to the identified system performance deficiency ~~and any long-term Load growth~~ that the project is intended to resolve ~~or address~~;

(b) ERCOT shall consider all comments received during the project comment process and factor reasonable comments into its independent review of the project;

(c) ERCOT will attempt to complete its independent review for a project in 120 days or less. If ERCOT is unable to complete its independent review based on RPG input within 120 days, ERCOT shall notify the RPG of the expected completion time;

(d) ERCOT may, at its discretion, discuss submitted transmission projects at meetings of the RPG in order to obtain additional input into its independent review; and

(e) ERCOT shall prepare a written report documenting the results of its independent review and recommendation on the project and shall distribute this report to the RPG.

3.11.4.7 Processing of Tier 1 Projects

(1) ERCOT shall conduct an independent review of a submitted Tier 1 project as follows:

(a) ERCOT's independent review will consist of studies and analyses necessary for ERCOT to make its assessment of whether the proposed project is needed and whether the proposed project is the preferred solution to the identified system performance deficiency ~~and any long-term Load growth~~ that the project is intended to resolve ~~or address~~;

(b) ERCOT will consider all comments received during the project comment process and factor reasonable comments into its independent review of the project;

(c) ERCOT will attempt to complete its independent review for a project in 150 days or less. If ERCOT is unable to complete its independent review based on RPG input within 150 days, ERCOT shall notify the RPG of the expected completion time;

(d) ERCOT may, at its discretion, discuss submitted transmission projects at meetings of the RPG in order to obtain additional input into its independent review; and

(e) ERCOT shall prepare a written report documenting the results of its independent review and recommendation on the project and shall distribute this report to the RPG.

(2) Tier 1 projects require ERCOT Board endorsement.

3.11.4.9 Regional Planning Group Acceptance and ERCOT Endorsement

Commented [EWG2]: Please note NPRR956 also proposes revisions to this section.

(1) For Tier 3 projects, successful resolution of all comments received from ERCOT and stakeholders during the project comment process will result in RPG acceptance of the proposed project. An RPG acceptance letter shall be sent to the TSP(s) for the project, the project submitter (if different from the TSP(s)), and posted on the MIS Secure Area. For Tier 2 projects, ERCOT's recommendation as a result of its independent review of the proposed project will constitute ERCOT endorsement of the need for a project except as noted in paragraph (4) below. For Tier 1 projects, ERCOT's endorsement is obtained upon affirmative vote of the ERCOT Board except as noted in paragraph (4) below. An ERCOT endorsement letter shall be sent to the TSP(s) for the project, the project submitter (if different from the TSP(s)), and the PUCT, and posted on the MIS Secure Area upon receipt of ERCOT's endorsement for Tier 1 and Tier 2 projects except as noted in paragraph (4) below. ~~For Tier 1, Tier 2, and Tier 3 projects that are justified, or partially justified under paragraph (3)(b) below, ERCOT may note quantifiable forecasted Load is part of the justification of the project, but the acceptance or endorsement will carry the same weight as it would if the project were justified by other needs.~~

(2) Following the completion of its independent review, ERCOT shall present all Tier 1 projects for which it finds a need to the ERCOT Board and shall provide a report to the ERCOT Board explaining the basis for its determination of need. Prior to presenting the project to the ERCOT Board, ERCOT shall present the project to the Technical Advisory Committee (TAC) for review and comment. Comments from TAC shall be included in the presentation to the ERCOT Board. ERCOT will make a reasonable effort to make these presentations to TAC and the ERCOT Board at the next regularly scheduled meetings following completion of its independent review of the project.

~~(3) If the asserted need for a Tier 1, Tier 2, or Tier 3 Tier 1 or Tier 2 project is based in part or in whole on:~~

~~(a) aA a service request or inquiry from a specificone or more cCustomers that have not signed an interconnection agreement and for which the TSP has provided no~~

other quantifiable evidence that credibly substantiates the forecasted Load growth, as described in Planning Guide Section 3.1.3, Project Evaluation, and Planning Guide Section 3.1.7, Steady State Transmission Planning Load Forecast ("unsupported Load"), a TSP may submit the project for RPG Project Review prior to that eCustomer signing a letter an agreement for the financial security of the necessary upgrades. However, ERCOT shall not issue an independent review recommending such a project until the eCustomer signs any required letter agreement, provides any required notice to proceed, and provides the full amount of any financial security required for the upgrades needed to serve that eCustomer. ERCOT shall notify the submitting TSP and the RPG of its determination whether the TSP's submitted Load is not based on an interconnection agreement or other quantifiable evidence of Load growth that ERCOT has deemed credible. If ERCOT has determined that the Load is not based on an interconnection agreement or other credible evidence, then within 15 days of such notification, the TSP shall notify ERCOT whether it wishes to proceed with review of the project. If the TSP notifies ERCOT that it wishes to proceed with review of the project, ERCOT shall notify the RPG, and the required RPG or ERCOT independent review process shall proceed using the submitted Load.

If a TSP elects to proceed with review:

For a Tier 1 or Tier 2 project, if ERCOT's independent review identifies a need for the project, ERCOT's independent review shall identify whether the unsupported Load is essential to the determination of need for the project or any portion thereof; and

(A) If the unsupported Load is essential to the determination of need for the project or any portion thereof, ERCOT's independent review shall not provide or recommend an endorsement for the project or portion that is attributable to the unsupported Load; and

If the unsupported Load is not essential to the determination of need for the project or any portion thereof, then for a Tier 1 project, ERCOT's independent review shall recommend an endorsement of that project, and, for a Tier 2 project, ERCOT's independent review shall endorse the project.

For a Tier 3 project, if the RPG process results in an acceptance of the project, ERCOT's acceptance letter for the project shall indicate that the asserted need for the project is based on the unsupported Load provided by the TSP.

(b) Multiple Customer service requests in a specific geographical area, ERCOT's independent review of such projects shall incorporate and consider any information provided by TSP(s) regarding the historical Load, and quantifiable evidence of the forecasted Load growth and any additional Load seeking interconnection in the project area, that may not have signed an agreement.

(34) If a TSP asserts a need for a proposed Tier 1 or Tier 2 project based in part or in whole on its own planning criteria, then ERCOT's independent review shall also consider whether

a reliability need exists under the TSP's criteria. If ERCOT identifies a reliability need under the TSP's criteria, then ERCOT shall recommend a project that would address that need as well as any reliability need identified under NERC or ERCOT criteria, but shall explicitly state in the independent review report that ERCOT has assumed the TSP's criteria are valid and that an assessment of the validity of the TSP's criteria is beyond the scope of ERCOT's responsibility. ERCOT or the ERCOT Board may provide a qualified endorsement of such a project if ERCOT determines that it is justified in part under ERCOT or NERC criteria, as described in paragraph (1) above. However, neither ERCOT nor the ERCOT Board shall endorse a project that is determined to be needed solely to meet a TSP's criteria.

Revised ERCOT Impact Analysis Report

NPRR Number	1180	NPRR Title	Inclusion of Forecasted Load in Planning Analyses
Impact Analysis Date		October 28, 2024	
Estimated Cost/Budgetary Impact		None. See Comments.	
Estimated Time Requirements		No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.	
ERCOT Staffing Impacts (across all areas)		See Comments.	
ERCOT Computer System Impacts		No impacts to ERCOT computer systems.	
ERCOT Business Function Impacts		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
NPRR1180 relates to implementation activities associated with Texas House Bill 5066 and Public Utility Commission of Texas (PUCT) Subst. R. 25.101 for any reliability-driven transmission project review conducted by ERCOT to incorporate the historical Load, forecasted Load growth, and additional Load seeking interconnection. The required FTEs to fulfill the implementation of NPRR1180, HB5066, and PUCT Subst. R. 25.101 will be included in the 2026-2027 budget submission. In the interim, ERCOT is fulfilling the requirements of this effort with contractors and by reprioritizing work within the impacted teams. The annual cost of the additional staff is between $2.0M and $2.4M. There will be ongoing operational impacts to the following ERCOT departments totaling 11.8 Full-Time Employees (FTEs) to support this effort: • Dynamic Studies (2.3 FTEs effort) • Regional Planning (4.1 FTEs effort)

- Regional Transmission Planning (4.2 FTEs effort)
- Load Forecasting & Analysis (1.2 FTEs effort)

ERCOT has assessed its ability to absorb the ongoing efforts of this effort with current staff and concluded the need for FTEs in the following departments:

- Dynamic Studies department (2 FTEs)
- Regional Planning department (4 FTEs)
- Regional Transmission Planning department (4 FTEs)
- Load Forecasting & Analysis (1 FTE)

• Dynamic Studies - department requires two additional FTEs to support the following work:

* 4,357 hours for conducting dynamic stability studies annually to evaluate the increase in substantiated load growth. Furthermore, these FTEs will also support and evaluate Regional Planning Group (RPG) project submissions, facilitate internal and external communications, enhance analytical tools, and provide support for both generation and load interconnection studies.

• Regional Planning - department requires four additional FTEs to support the expected increase in RPG project submissions:

* 7,554 hours for performing additional Tier 1, Tier 2, and Tier 3 RPG project evaluations beyond current levels.

• Regional Transmission Planning - department requires four additional FTEs to support the following work:

* 7,766 hours to support the analysis of additional reliability violations introduced by the additional loads under North American Electric Reliability Corporation (NERC) and ERCOT planning criteria including the maintenance outage reliability criteria, to develop the Corrective Action Plans (CAPs) to address the additional issues for the planning events that load shed is not allowed, or to perform load shed and cascading analysis for the planning and extreme events that load shed is allowed.

• Load Forecasting & Analysis - department requires one additional FTE to support the following work:

*2,200 hours to support Long Term Load Forecast (LTLF) = 400 hours per year for contract review, 600 hours per year for ramp and profile model creation and forecasting, 400 hours reasonability and integration to LTLF, 500 hours per year for periodic updates to large load request and integration. 300 hours per year for reporting and presentation of new and existing large loads impact to LTLF.

Board Report

NPRR Number	1239	NPRR Title	Access to Market Information
Date of Decision		December 3, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Between $50k and $100k Project Duration: 3 to 6 months	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Priority – 2025; Rank – 4540	
Nodal Protocol Sections Requiring Revision		3.19.3, Long-Term Constraint Competitiveness Test 4.4.9.4.1, Mitigated Offer Cap 4.5.3, Communicating DAM Results 5.3, ERCOT Security Sequence Responsibilities 5.5.1, Security Sequence 5.5.2, Reliability Unit Commitment (RUC) Process 5.7.4, RUC Make-Whole Charges 6.5.7.1.13, Data Inputs and Outputs for the Real-Time Sequence and SCED 6.5.7.6.2.1, Deployment of Regulation Service 6.5.9.5.1, Registration and Posting of BLT Points 8.1, QSE and Resource Performance Monitoring 8.1.2, Current Operating Plan (COP) Performance Requirements 8.5.1.2, Reporting 9.14.4, ERCOT Processing of Disputes 9.14.4.1.6, ADR 9.19, Default Uplift Invoices 11.5.1.2, TSP and/or DSP Load Data Posting/Availability 11.5.2.2, General Public Data Posting/Availability 12.3, MIS Administrative and Design Requirements	
Related Documents Requiring Revision/Related Revision Requests		Nodal Operating Guide Revision Request (NOGRR) 266, Related to NPRR1239, Access to Market Information	
Revision Description		This Nodal Protocol Revision Request (NPRR) moves from the Market Information System (MIS) Secure Area to the public ERCOT	

	website reports that do not contain ERCOT Critical Energy Infrastructure Information (ECEII). ERCOT Staff analyzed reports in the MIS Secure Area, along with existing Protocols for posting requirements, and identified no ongoing basis for holding in the MIS Secure Area reports determined to contain only information for a market audience and not ECEII.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	Reports that are not Protected Information in the MIS Secure Area are available to any registered Market Participant who requests a standard Digital Certificate from ERCOT; and paragraph (1)(j) of Section 1.3.1.2, Items Not Considered Protected Information, treats similarly requirements to post non-Protected Information on the ERCOT website or on the MIS Secure Area. This NPRR moves reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports that are not Protected Information without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request. Stakeholders may want to evaluate the value of producing the report in Section 6, Adjustment Period and Real-Time Operations, that shows registration details of all registered Block Load Transfers. This NPRR proposes posting the report on the ERCOT website, though records suggest Market Participants haven't opened the report since 2019. Governor test results in Section 8, Performance Monitoring, are not ECEII, and reports of test results are currently only generated as needed upon request. The proposed revision would continue the

	practice of producing the reports only upon request but post them on the ERCOT website.
PRS Decision	On 7/18/24, PRS voted unanimously to table NPRR1239. All Market Segments participated in the vote. On 9/12/24, PRS voted unanimously to recommend approval of NPRR1239 as submitted. All Market Segments participated in the vote. On 10/17/24, PRS voted unanimously to table NPRR1239. On 11/14/24, PRS voted unanimously to endorse and forward to TAC the 10/17/24 PRS Report and 10/29/24 Revised Impact Analysis for NPRR1239 with a recommended priority of 2025 and a rank of 4540. All Market Segments participated in the vote.
Summary of PRS Discussion	On 7/18/24, ERCOT Staff presented NPRR1239. Some participants expressed concern for unintended consequences and requested additional time to review the language, and to consider use of the ERCOT website. On 9/12/24, participants noted ROS endorsement of NPRR1239. On 10/17/24, participants reviewed the 7/2/24 Impact Analysis. ERCOT Staff requested tabling NPRR1239 to allow for additional internal review of the Impact Analysis. On 11/14/24, participants reviewed the 10/29/24 Revised Impact Analysis.
TAC Decision	On 11/20/24, TAC voted unanimously to recommend approval of NPRR1239 as recommended by PRS in the 11/14/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/20/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)

Board Report

Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1239 as recommended by TAC in the 11/20/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1239 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1239.
ERCOT Opinion	ERCOT supports approval of NPRR1239.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1239 and believes it provides a positive market impact by improving access and transparency by moving reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request.

Sponsor	
Name	Kim Rainwater
E-mail Address	Kimberly.Rainwater@ercot.com
Company	ERCOT
Phone Number	512-225-7179
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com
Phone Number	512-225-7027

Comments Received

Comment Author	Comment Summary
ROS 080224	Requested PRS continue to table NPRR1239
ROS 091024	Endorsed NPRR1239 as submitted

Market Rules Notes

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

- NPRR1058, Resource Offer Modernization (unboxed 8/23/24)
  - Section 4.4.9.4.1
- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
  - Section 4.5.3

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

- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  - Section 5.5.2
  - Section 5.7.4
- NPRR1245, Additional Clarifying Revisions to Real-Time Co-Optimization
  - Section 4.4.9.4.1
  - Section 5.5.2
- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
  - Section 6.5.7.1.13
  - Section 8.1
- NPRR1249, Publication of Shift Factors for All Active Transmission Constraints in the RTM
  - Section 6.5.7.1.13
- NPRR1255, Introduction of Mitigation of ESRs
  - Section 4.4.9.4.1

Proposed Protocol Language Revision

3.19.3 Long-Term Constraint Competitiveness Test

(1) The Long-Term CCT process is executed once a year and provides a projection of Competitive Constraints for the month with the highest forecasted Demand in the following year.

(2) The Long-Term CCT performs analysis on a selected set of constraints.

(3) A constraint is classified as a Competitive Constraint for the monthly case if it meets all of the following conditions:

(a) The ECI is less than ECIT1 on the import side of the constraint;

(b) The constraint can be resolved by eliminating all Available Capacity for a Resource on the import side, except nuclear capacity and minimum-energy amounts of coal and lignite capacity, that is Managed Capacity for a DME during peak Load conditions; and

(c) There are negative Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that have an absolute value greater than or equal to SFP2.

[NPRR1182: Replace paragraph (c) above with the following upon system implementation:]

(c) There are Shift Factors corresponding to Electrical Buses with Available Capacity for a Resource that can help resolve the constraint by increasing power injection or reducing power withdrawal that have an absolute value greater than or equal to SFP2.

(4) Any constraint that is analyzed and does not meet the conditions in paragraph (3) above will be designated as a Non-Competitive Constraint for the monthly case.

(5) ERCOT shall update and post the list of Competitive Constraints identified by the Long-Term CCT on the ~~MIS Secure Area~~ERCOT website. The list of Competitive Constraints shall be posted at least 30 days prior to the first of the year.

4.4.9.4.1 Mitigated Offer Cap

(1) Energy Offer Curves may be subject to mitigation in Real-Time operations under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Cap (MOC). ERCOT shall construct an incremental MOC curve in accordance with Section 6.5.7.3 such that each point on the MOC curve is calculated as follows:

[NPRR1014: Replace paragraph (1) above with the following upon system implementation:]

(1) Energy Offer Curves and Energy Bid/Offer Curves may be subject to mitigation in Real-Time operations under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Cap (MOC). For Generation Resources, ERCOT shall construct an incremental MOC curve in accordance with Section 6.5.7.3 such that each point on the MOC curve is calculated as follows:

$MOC_{q, r, h} = Max [GIHR_{q, r} * Max(FIP, WAFP_{q, r, h}), (IHR_{q, r} * FPRC_{q, r} + OM_{q, r})]$

Where,

If a QSE has submitted an Energy Offer Curve on behalf of a Generation Resource and the Generation Resource has approved verifiable costs, then

$FPRC_{q, r} = Max(WAFP_{q, r, h}, FIP + FA_{q, r}) * RTPERFIP_{q, r} / 100 + FOP * RTPERFOP_{q, r} / 100$

If a QSE has not submitted an Energy Offer Curve on behalf of a Generation Resource and the Generation Resource has approved verifiable costs, then

$FPRC_{q, r} = Max(WAFP_{q, r, h}, FIP + FA_{q, r}) * GASPEROL_{q, r} / 100 + FOP * OILPEROL_{q, r} / 100 + (SFP + FA_{q, r}) * SFPEROL_{q, r} / 100$

The above variables are defined as follows:

Variable	Unit	Definition
$MOC_{q, r, h}$	$/MWh	*Mitigated Offer Cap per Resource*—The MOC for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$GIHR_{q, r}$	MMBtu/MWh	*Generic Incremental Heat Rate*—The generic, single-value, incremental heat rate. For Generation Resources with a Commercial Operations Date on or before January 1, 2004, the generic incremental heat rate shall be set to 10.5. For Generation Resources that have a Commercial Operations Date after January 1, 2004, this value shall be set to 14.5. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$IHR_{q, r}$	MMBtu/MWh	*Verifiable Incremental Heat Rate per Resource*—The verifiable incremental heat rate curve for Resource *r*, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
FIP	$/MMBtu	*Fuel Index Price*—The natural gas index price as defined in Section 2.1, Definitions.
$RTPERFIP_{q, r}$	none	*Fuel Index Price Percentage*—The percentage of natural gas used by Resource *r* to operate above LSL, as submitted with the energy offer curve.
FOP	$/MMBtu	*Fuel Oil Price*—The fuel oil index price as defined in Section 2.1.
$RTPERFOP_{q, r}$	none	*Fuel Oil Price Percentage*—The percentage of fuel oil used by Resource *r* to operate above LSL, as submitted with the energy offer curve.
SFP	$/MMBtu	*Solid Fuel Price*—The solid fuel index price is $1.50.
$FPRC_{q, r}$	$/MMBtu	*Fuel Price Calculated per Resource*—The calculated index price for fuel for the Resource based on the Resources fuel mix. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$GASPEROL_{q, r}$	none	*Percent of Natural Gas to Operate Above LSL*—The percentage of natural gas used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	Unit	Definition
$OILPEROL_{q, r}$	none	*Percent of Oil to Operate Above LSL*—The percentage of fuel oil used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$SFPEROL_{q, r}$	none	*Percent of Solid Fuel to Operate Above LSL*—The percentage of solid fuel used by Resource *r* to operate above LSL, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$FA_{q, r}$	$/MMBtu	*Fuel Adder*—The fuel adder is the average cost above the index price Resource *r* has paid to obtain fuel. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
$OM_{q, r}$	$/MWh	*Variable Operations and Maintenance Cost above LSL*—The O&M cost for Resource *r* to operate above LSL, including an adjustment for emissions costs, as approved in the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. See the Verifiable Cost Manual for additional information.
$WAFP_{q, r, h}$	$/MMBtu	*Weighted Average Fuel Price*—The volume-weighted average intraday, same-day and spot fuel price, the projected incremental fuel consistent with a fuel supply contract(s), or a combination of these two prices, submitted to ERCOT during the Adjustment Period for a specific Resource and specific hour within the Operating Day, as described in paragraph (1)(d) below. ***[NPRR1177: Replace the definition above with the following on January 1, 2025:]*** *Weighted Average Fuel Price*—The volume-weighted average intraday, same-day and spot price of fuel submitted to ERCOT during the Adjustment Period for a specific Resource and specific hour within the Operating Day, as described in paragraph (1)(d) below.
q	none	A QSE.
r	none	A Generation Resource.
h	none	The Operating Hour.

(a) For a Resource contracted by ERCOT under paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority, ERCOT shall increase the O&M cost such that every point on the MOC curve is greater than the SWCAP in $/MWh.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (a) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(a) For a Resource contracted by ERCOT under paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority, ERCOT shall increase the O&M cost such that every point on the MOC curve is greater than the effective Value of Lost Load (VOLL) in $/MWh.

(b) Notwithstanding the MOC calculation described in paragraph (1) above, the MOC for ESRs shall be set at the SWCAP. No later than December 31, 2023, ERCOT and stakeholders shall submit a report to TAC that includes a recommendation to continue the existing approach or a proposal to implement an alternative approach to determine the MOC for ESRs.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (b) above with the following upon the system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(b) Notwithstanding the MOC calculation described in paragraph (1) above, the MOC for ESRs shall be set at the RTSWCAP. No later than December 31, 2023, ERCOT and stakeholders shall submit a report to TAC that includes a recommendation to continue the existing approach or a proposal to implement an alternative approach to determine the MOC for ESRs.

(c) For Quick Start Generation Resources (QSGRs) the MOC shall be adjusted in accordance with Verifiable Cost Manual Appendix 7, Calculation of the Variable O&M Value and Incremental Heat Rate used in Real Time Mitigation for Quick Start Generation Resources (QSGRs).

[NPRR1008 and NPRR1014: Insert applicable portions of paragraph (d) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly:]

(d) For On-line hydro Generation Resources not operating in Synchronous Condenser Fast-Response mode, the MOC shall be adjusted in accordance with Verifiable Cost Manual, Appendix 12, Calculation of the Variable O&M Value and Incremental Heat Rate used in Real Time Mitigation for On-Line Hydro Generation Resources not operating in Synchronous Condenser Fast-Response mode.

(d) During the Adjustment Period, a QSE representing a Resource may submit Exceptional Fuel Cost as a volume-weighted average fuel price for use in the MOC calculation for that Resource. To qualify as Exceptional Fuel Cost, the submission must meet the following conditions:

(i) For all Resources, the weighted average fuel price must exceed FIP for the applicable Operating Day, plus a threshold parameter value of $1/MMBtu, plus the applicable fuel adder. For Resources without approved verifiable costs, the fuel adder will be set to the default value assigned to Resources with approved verifiable costs, as defined in the Verifiable Cost Manual. The threshold parameter value in this paragraph shall be recommended by the Wholesale Market Subcommittee (WMS) and approved by the

Technical Advisory Committee (TAC). ERCOT shall update the threshold value on the first day of the month following TAC approval unless otherwise directed by the TAC. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.

(ii) Fixed cost (fees, penalties and similar non-gas costs) may not be included in the calculation of the weighted average fuel price.

(iii) The weighted average fuel price in paragraph (1) above must be a single value and based on the following fuel price options:

(A) A volume-weighted price considering all intra-day, same day, and spot fuel purchases for the Resource; or

(B) A projected fuel price for a Resource with a fuel supply contract(s) that also has submitted an Energy Offer Curve for the Operating Hour where the Energy Offer Curve is calculated as the incremental heat rate times the incremental fuel price plus Operations and Maintenance (O&M) cost; or

(C) A combination of the above two options.

A weighted average fuel price based on actual fuel purchases must be included in the calculation of the weighted average fuel price in paragraph (1) above. These must account for at least 10% of the total fuel volume burned by the applicable Resource for the hour for which the weighted average fuel price is computed. A projected incremental fuel price must be consistent with the terms of the fuel supply contract(s). A weighted average fuel price based on a combination of these options must meet the requirements described for each of the options. As noted in paragraph (j) below, the methodology used in the allocation of the cost and volume of fuel to the Resource for the hour is subject to validation by ERCOT.

[NPRR1177: Replace paragraph (iii) above with the following on January 1, 2025:]

(iii) All intra-day, same day, and spot fuel purchases must be included in the calculation of the weighted average fuel price in paragraph (1) above. These must account for at least 10% of the total fuel volume burned by the applicable Resource for the hour for which the weighted average fuel price is computed. As noted in paragraph (j) below, the methodology used in the allocation of the cost and volume of purchased fuel to the Resource for the hour is subject to validation by ERCOT.

(iv) Weighted average fuel prices must be submitted individually for each Operating Hour for which they are applicable. Values submitted outside

of the Adjustment Period will be rejected and not used in the calculation of the MOC for the designated Operating Hour.

(v) A projected volume-weighted average fuel price must be consistent with the Energy Offer Curve for each Operating Hour for which they are applicable, and consistent with the signed and executed fuel supply contract(s) for each Resource.

(vi) An Exceptional Fuel Cost submitted based on projected fuel prices may not match with the actual volume-weighted average fuel price due to prospective costs and/or contractual costs.

[NPRR1177: Delete paragraphs (v) and (vi) above on January 1, 2025.]

(e) ERCOT may notify the Independent Market Monitor (IMM) if a QSE submits an Exceptional Fuel Cost.

(f) The day following an Operating Day for which an Exceptional Fuel Cost is submitted, ERCOT shall post a report on the ERCOT website indicating the affected Operating Hours and the number of Resources for which a QSE submitted Exceptional Fuel Cost for a particular Operating Day.

(g) No later than 1700 Central Prevailing Time (CPT) on the 15th day following an Exceptional Fuel Cost submission, the submitting QSE shall provide ERCOT with the calculation of the weighted average fuel price, intraday or same-day fuel purchases, if applicable, and any available supporting documentation. Such information may include, but is not limited to, documents of the following nature: relevant contracts between the QSE or Resource Entity and fuel supplier, trade logs, transportation, storage, balancing and distribution agreements, calculation of the weighted average fuel price, or any other documentation necessary to support the Exceptional Fuel Cost price and volume for the applicable period(s).

(h) No later than 1700 Central Prevailing Time (CPT) on the 60th day following an Exceptional Fuel Cost submission, the submitting QSE shall provide ERCOT with all supporting documentation not previously provided to ERCOT. No supporting documentation will be accepted after the 60th day.

(i) The accuracy of submitted Exceptional Fuel Cost and the need for purchasing intraday or same-day gas must be attested to by a duly authorized officer or agent of the QSE representing the Resource. The attestation must be provided in a standardized format acceptable to ERCOT and submitted with the other documentation described in paragraph (g) above. An attestation for Exceptional Fuel Costs must state that the costs are accurate and variable, based on the dispatch of the Resource.

[NPRR1177: Replace paragraph (i) above with the following on January 1, 2025:]

(i) The accuracy of submitted Exceptional Fuel Cost and the need for purchasing intraday or same-day gas must be attested to by a duly authorized officer or agent of the QSE representing the Resource. The attestation must be provided in a standardized format acceptable to ERCOT and submitted with the other documentation described in paragraph (g) above.

(j) ERCOT will use the supporting documentation to validate the Exceptional Fuel Cost for the applicable period. Validation will include, but not be limited to, the cost and the quantity of purchased fuel, Resource-specific heat rates, and the methodology used in the allocation of the cost and volume of purchased fuel, if applicable, to the Resource for the applicable hour used in the weighted average fuel price calculation. In connection with the validation process ERCOT may request additional documentation or clarification of previously submitted documentation. Such requests must be honored within ten Business Days.

(k) At ERCOT's sole discretion, submission and follow-up information deadlines may be extended on a case-by-case basis.

(l) The documentation described in paragraphs (g) through (j) above is only required for the hours for which Exceptional Fuel Costs were submitted and the Resource was subject to mitigation.

(m) For Resources submitting Exceptional Fuel Costs based on projected incremental fuel prices based on a contract(s) the QSE must submit to ERCOT all applicable fuel supply contracts at least ten Business Days in advance of submitting Exceptional Fuel Costs. ERCOT may, at any time, notify the QSE of any cost identified in the contract that is ineligible for inclusion in any Exceptional Fuel Cost submission. Upon receiving such notification, the QSE shall ensure that such cost is not included in any Exceptional Fuel Cost submission or in any Energy Offer Curve submission for any hours for which Exceptional Fuel Costs are submitted. The absence of any such notification shall not imply that such cost is eligible for inclusion in any Exceptional Fuel Cost submission or in any Energy Offer Curve submission.

[NPRR1177: Delete paragraphs (l) and (m) above on January 1, 2025.]

4.5.3 Communicating DAM Results

(1) As soon as practicable, but no later than 1330 in the Day-Ahead, ERCOT shall notify the parties to each cleared DAM transaction (e.g., the buyer and the seller) of the results of the DAM as follows:

(a) Awarded Ancillary Service Offers, specifying Resource, MW, Ancillary Service type, and price, for each hour of the awarded offer;

(b) Awarded energy offers from Three-Part Supply Offers and from DAM Energy-Only Offers, specifying Resource (except for DAM Energy-Only Offers), MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded offer;

(c) Awarded DAM Energy Bids, specifying MWh, Settlement Point, and Settlement Point Price for each hour of the awarded bid; and

(d) Awarded PTP Obligation Bids, number of PTP Obligations in MW, source and sink Settlement Points, and price for each Settlement Interval of the awarded bid.

[NPRR1008, NPRR1014, and NPRR1188: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014 or NPRR1188:]

(1) As soon as practicable, but no later than 1330 in the Day-Ahead, ERCOT shall notify the parties to each cleared DAM transaction (e.g., the buyer and the seller) of the results of the DAM as follows:

(a) Awarded Resource-Specific Ancillary Service Offers, specifying Resource, MW, Ancillary Service type, and price, for each hour of the awarded offer;

(b) Awarded Ancillary Service Only Offers, specifying MW, Ancillary Service type, and price, for each hour of the awarded offer;

(c) Awarded energy offers from Three-Part Supply Offers and from DAM Energy-Only Offers, specifying Resource (except for DAM Energy-Only Offers), MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded offer;

(d) Awarded DAM Energy Bids and Energy Bid Curves, specifying MWh, Settlement Point, and Settlement Point Price for each hour of the awarded bid;

(e) Awarded Energy Bid/Offer Curves, specifying Resource, MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded bid/offer; and

(f) Awarded PTP Obligation Bids, number of PTP Obligations in MW, source and sink Settlement Points, and price for each Settlement Interval of the awarded bid.

(2) As soon as practicable, but no later than 1330, ERCOT shall post on the ERCOT website the hourly:

(a) Day-Ahead MCPC for each type of Ancillary Service for each hour of the Operating Day;

(b) DASPPs for each Settlement Point for each hour of the Operating Day;

(c) Day-Ahead hourly LMPs for each Electrical Bus for each hour of the Operating Day;

(d) Shadow Prices for every binding constraint for each hour of the Operating Day;

(e) Quantity of total Ancillary Service Offers received in the DAM, in MW by Ancillary Service type for each hour of the Operating Day;

(f) Energy bought in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Bids (in MWh) bought in the DAM at each Settlement Point for each hour of the Operating Day; and

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that sink at each Settlement Point for each hour of the Operating Day.

(g) Energy sold in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Offers (in MWh), from Three-Part Supply Offers and DAM Energy Only Offers, bought in the DAM at each Settlement Point for each hour of the Operating Day; and

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that source at each Settlement Point for each hour of the Operating Day.

(h) Aggregated Ancillary Service Offer Curve of all Ancillary Service Offers for each type of Ancillary Service for each hour of the Operating Day;

(i) Electrically Similar Settlement Points used during the DAM clearing process; and

(j) Settlement Points that were de-energized in the base case; and

(k) System Lambda.

[NPRR1008, NPRR1014, and NPRR1188: Replace applicable portions of paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014 or NPRR1188:]

(2) As soon as practicable, but no later than 1330, ERCOT shall post on the ERCOT website the hourly:

(a) Day-Ahead MCPC for each type of Ancillary Service for each hour of the Operating Day;

(b) DASPPs for each Settlement Point for each hour of the Operating Day;

(c) Day-Ahead hourly LMPs for each Electrical Bus for each hour of the Operating Day;

(d) Shadow Prices for every binding constraint for each hour of the Operating Day;

(e) Energy bought in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Bids and Energy Bid Curves (in MWh) bought in the DAM at each Settlement Point for each hour of the Operating Day;

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that sink at each Settlement Point for each hour of the Operating Day; and

(iii) The total absolute value quantity of awards to bid portions of Energy Bid/Offer Curves (in MWh) cleared in the DAM at each Settlement Point for each hour of the Operating Day.

(f) Energy sold in the DAM consisting of the following:

(i) The total quantity of awarded DAM Energy Offers (in MWh), from Three-Part Supply Offers and DAM Energy Only Offers, bought in the DAM at each Settlement Point for each hour of the Operating Day;

(ii) The total quantity of awarded PTP Obligation Bids (in MWh) cleared in the DAM that source at each Settlement Point for each hour of the Operating Day; and

(iii) The total quantity of awards to offer portions of Energy Bid/Offer Curves (in MWh) cleared in the DAM at each Settlement Point for each hour of the Operating Day.

(g) Aggregated Ancillary Service Offer Curve of all Ancillary Service Offers (including both Resource-Specific Ancillary Service Offers and Ancillary Service Only Offers) for each type of Ancillary Service for each hour of the Operating Day;

(h) Electrically Similar Settlement Points used during the DAM clearing process;

(i) Settlement Points that were de-energized in the base case;

(j) System Lambda; and

(k) Ancillary Services sold in the DAM consisting of the total quantity of awarded Resource-Specific Ancillary Service Offers and Ancillary Service Only Offers, for each Ancillary Service for each hour of the Operating Day.

(3) ERCOT shall monitor Day-Ahead MCPCs and Day-Ahead hourly LMPs for errors and if there are conditions that cause the price to be questionable, ERCOT shall notify all Market Participants that the DAM prices are under investigation as soon as practicable.

(4) ERCOT shall correct prices for an Operating Day when a market solution is determined to be invalid or invalid prices are identified in an otherwise valid market solution, accurate prices can be determined, and the impact of the price correction is significant. The following are some reasons that may cause an invalid market solution or invalid prices in a valid market solution.

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

(b) Software error: Pricing errors may occur due to software implementation errors in DAM pre-processing, DAM clearing process, and/or DAM post processing.

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

(5) For purposes of a price correction performed prior to 1000 on the second Business Day after the Operating Day, the impact of a price correction is considered significant, as that term is used in paragraph (4) above, for the Operating Day when:

(a) The absolute value change to any single DAM Settlement Point Price at a Resource Node or Day-Ahead MCPC is greater than $0.05/MWh;

(b) The price correction would require ERCOT to change more than ten DAM Settlement Point Prices and Day-Ahead MCPCs; or

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

(6) All DAM LMPs, MCPCs, and Settlement Point Prices are final at 1000 of the second Business Day after the Operating Day.

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

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

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

(iii) ERCOT's authority to grant relief to a Market Participant pursuant to the timelines specified in Section 20, Alternative Dispute Resolution Procedure.

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

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

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

(c) The ERCOT Board may review and change DAM LMPs, MCPCs, or Settlement Point Prices if ERCOT gave timely notice to Market Participants and the ERCOT Board finds that such prices should be corrected for an Operating Day.

(d) In review of DAM LMPs, MCPCs, or Settlement Point Prices, the ERCOT Board may rely on the same reasons identified in paragraph (4) above to find that the prices should be corrected for an Operating Day.

(7) As soon as practicable, but no later than 1330, ERCOT shall make available the Day-Ahead Shift Factors for binding constraints in the DAM and post to the ~~Market Information System (MIS) Secure Area~~ERCOT website.

5.3 ERCOT Security Sequence Responsibilities

(1) ERCOT shall start the Day-Ahead Reliability Unit Commitment (DRUC) process at 1430 in the Day-Ahead.

(2) For each DRUC, ERCOT shall use a snapshot of Resource commitments taken at 1430 in the Day-Ahead for Reliability Unit Commitment (RUC) Settlement. For each Hourly Reliability Unit Commitment (HRUC), ERCOT shall use a snapshot of Resource commitments from each Qualified Scheduling Entity's (QSE's) most recently submitted Current Operating Plan (COP) before HRUC execution for RUC Settlement.

(3) For each RUC process, ERCOT shall:

(a) Execute the Security Sequence described in Section 5.5, Security Sequence, Including RUC, including:

(i) Validating Three-Part Supply Offers, defined in Section 4.4.9.1, Three-Part Supply Offers;

[NPRR1009 and NPRR1014: Replace item (i) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014:]

(i) Validating Three-Part Supply Offers, defined in Section 4.4.9.1, Three-Part Supply Offers, Energy Bid/Offer Curves, defined in Section 4.4.9.7, Energy Bid/Offer Curve, and Ancillary Service Offers, defined in Section 4.4.7.2, Ancillary Service Offers;

(ii) Reviewing the Resource commitment recommendations made by the RUC algorithm; and

(iii) Reviewing the list of Off-Line Available Resources having a start-up time of one hour or less;

(b) Post to the ~~Market Information System (MIS) Secure Area~~ERCOT website all Resources that were committed or decommitted by the RUC process including verbal RUC commitments and decommitments and Weekly Reliability Unit Commitment (WRUC) instructions;

(c) Post to the ERCOT website all active and binding transmission constraints (contingency and overloaded element pair information where available) used as inputs to the RUC;

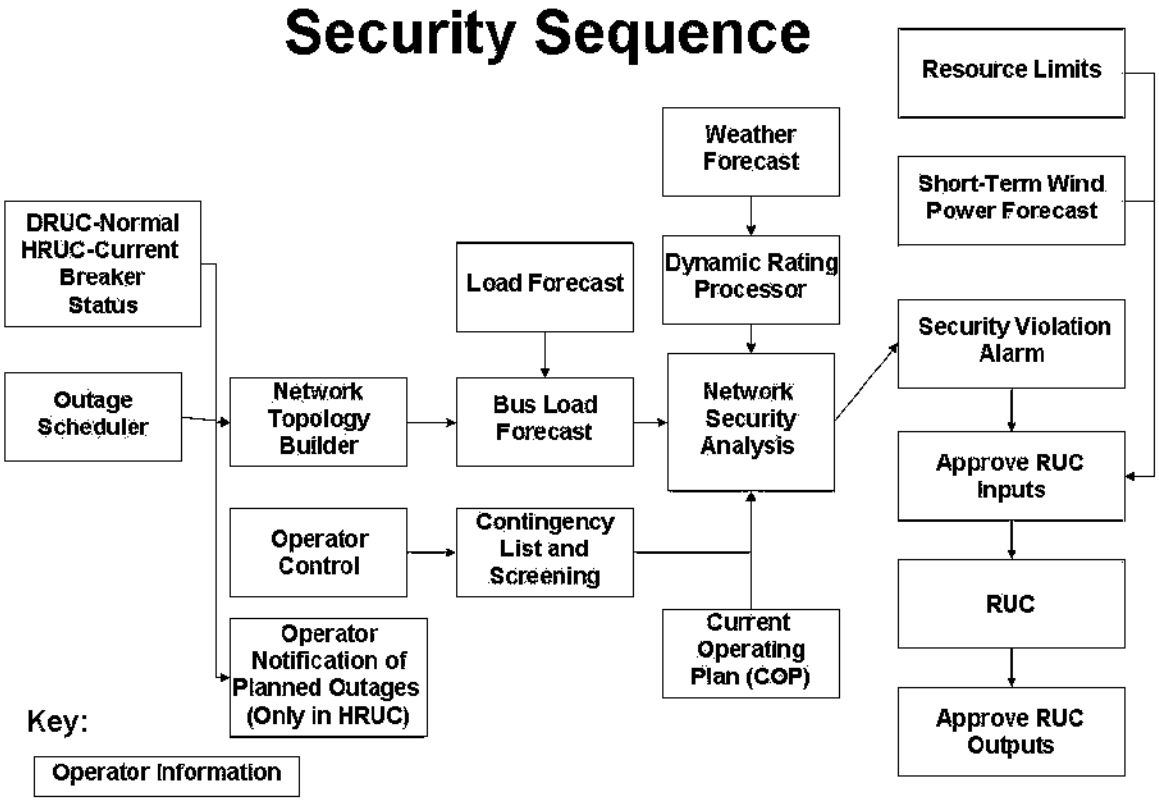
(d) Issue Dispatch Instructions to notify each QSE of its Resource commitments or decommitments; and

(e) Post to the ~~MIS Secure Area~~ERCOT website all Resources that were committed by the RUC process, including verbal RUC commitments, but were subsequently cancelled by the ERCOT Operator.

(4) ERCOT shall provide each QSE with the information necessary to pre-validate their data for DRUC and HRUC, including publishing validation rules for offers, bids, and trades.

5.5.1 Security Sequence

(1) The figure below highlights the key computational modules and processes that are used in the Security Sequence:



(2) The Security Sequence uses computational modules functionally similar to those used in Real-Time Sequence, however, the inputs into the Security Sequence are based on a snapshot of projected hourly system conditions and constraints rather than Real-Time data.

(3) The Security Sequence uses the status of all transmission breakers and switches (current status for the first hour and normal status for all other hours of Hourly Reliability Unit Commitment (HRUC) and normal status for all hours of Day-Ahead Reliability Unit Commitment (DRUC)), updated for approved Planned Outages for equipment out of service and returned to service for building a representation of the ERCOT Transmission Grid for each hour of the Reliability Unit Commitment (RUC) Study Period. The

Network Topology Processor constructs a network model for each hour that must be used by the Bus Load Forecast to estimate the hourly Load for each transmission bus.

(4) The weather forecast obtained by ERCOT must be provided to the Dynamic Rating Processor to create weather-adjusted MVA limits for each hour of the RUC Study Period for all transmission lines and transformers that have Dynamic Ratings.

(5) ERCOT shall analyze base configuration, select n-1 contingencies and select n-2 contingencies under the Operating Guides. The Operating Guides must also specify the criteria by which ERCOT may remove contingencies from the list. ERCOT shall post to the Market Information System (MIS) Secure Area the standard contingency list, including identification of changes from previous versions before being used in the Security Sequence. ERCOT shall evaluate the need for Resource-specific deployments during Real-Time operations for management of congestion consistent with the Operating Guides.

(6) ERCOT shall also post to the MIS Secure Area any contingencies temporarily removed from the standard contingency list by ERCOT immediately after successful execution of the Security Sequence. ERCOT shall include the reason for removal of any contingency as soon as practicable but not later than one hour after removal.

(7) As part of the Network Security Analysis (NSA), for each hour of the RUC Study Period, ERCOT shall analyze all selected contingencies and perform the following:

(a) Perform full AC analysis of all contingencies;

(b) Monitor element and bus voltage limit violations; and

(c) Monitor transmission line and transformer security violations.

(8) As part of the NSA, if there is an approved Remedial Action Plan (RAP) available, it must be used before considering a Resource commitment.

(9) ERCOT shall review all security violations prior to RUC execution.

(10) All Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs) and RAPs modeled in the Network Operations Model shall be included in the contingency analysis. The computational modules must enable ERCOT to analyze contingencies, including the effects of all RASs and AMPs included in the Network Operations Model.

(11) ERCOT may deselect certain contingencies known to cause errors or that otherwise result in inconclusive study output in the RUC. On continued de-selection of contingencies, ERCOT shall prepare an analysis to determine the cause of the error. ERCOT may use information from the Day-Ahead processes as decision support during the Hour-Ahead processes. ERCOT shall post to the ~~MIS Secure Area~~ERCOT website any contingencies deselected by ERCOT and must include the reason for removal as soon as practicable, but not later than one hour after deselection.

5.5.2 Reliability Unit Commitment (RUC) Process

(1) The RUC process recommends commitment of Generation Resources, to match ERCOT's forecasted Load including Direct Current Tie (DC Tie) Schedules, subject to all transmission constraints and Resource performance characteristics. The RUC process takes into account Resources already committed in the Current Operating Plans (COPs), Resources already committed in previous RUCs, Off-Line Available Resources having a start-up time of one hour or less, and Resource capacity already committed to provide Ancillary Service. The formulation of the RUC objective function must employ penalty factors on violations of security constraints. The objective of the RUC process is to minimize costs based on the Resource costs described in paragraphs (5) through (9) below. For all hours of the RUC Study Period within the RUC process, Quick Start Generation Resources (QSGRs) with a COP Resource Status of OFFQS shall be considered as On-Line with Low Sustained Limit (LSL) at zero MW. QSGRs with a Resource Status of OFFQS shall only be committed by ERCOT through a RUC instruction in instances when a reliability issue would not otherwise be managed through Dispatch Instructions from Security-Constrained Economic Dispatch (SCED). For On-Line ESRs, the Hour Beginning Planned State of Charge (SOC) values provided in the COP for a given hour are discounted to ensure sufficient SOC is preserved to meet Ancillary Service Resource Responsibilities, as reflected in the COP. Any remaining SOC on the ESR will be considered available for energy dispatch by RUC while respecting the Minimum State of Charge (MinSOC) and Maximum State of Charge (MaxSOC) values provided in the COP.

(2) The RUC process can recommend Resource decommitment. ERCOT may only decommit a Resource to resolve transmission constraints that are otherwise unresolvable. Qualifying Facilities (QFs) may be decommitted only after all other types of Resources have been assessed for decommitment. In addition, the HRUC process provides decision support to ERCOT regarding a Resource decommitment requested by a Qualified Scheduling Entity (QSE).

(3) ERCOT shall review the RUC-recommended Resource commitments and the list of Off-Line Available Resources having a start-up time of one hour or less to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. During the RUC process, ERCOT may also review and commit, through a RUC instruction, Combined Cycle Generation Resources that are currently planned to be On-Line but are capable of transitioning to a configuration with additional capacity. ERCOT may deselect Resources recommended in DRUC and in all HRUC processes if in ERCOT's sole discretion there is enough time to commit those Resources in the future HRUC processes, taking into account the Resources' start-up times, to meet ERCOT System reliability. After each RUC run, ERCOT shall post the amount of capacity deselected per hour in the RUC Study Period to the ~~MIS Secure Area~~ERCOT website. A Generation Resource shown as On-Line and available for SCED dispatch for an hour in its COP prior to a DRUC or HRUC process execution, according to Section 5.3, ERCOT Security Sequence Responsibilities, will be considered self-committed for that hour. For purpose of Settlement, snapshot data will be used as specified in paragraph (2) of Section 5.3. ERCOT shall issue RUC instructions to each QSE specifying its Resources that have

been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the ~~MIS Secure Area~~ ERCOT website any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.

(4) A QSE shall notify the ERCOT Operator of any physical limitation that impacts its Resource's ability to start that is not reflected in the Resource's COP or the Resource's startup time, minimum On-Line time, or minimum Off-Line time. The following shall apply:

(a) If a Resource receives a RUC Dispatch Instruction that it cannot meet due to a physical limitation described in paragraph (4) above, the QSE representing the Resource shall notify the ERCOT Operator of the inability to fully comply with the instruction and shall comply with the instruction to the best of the Resource's ability. If the QSE has provided the ERCOT Operator notice of that limitation at least seven days prior to the Operating Day in which the instruction occurs, the QSE shall be excused from complying with the portion of the RUC Dispatch Instruction that it could not meet due to the identified limitation.

(b) If a QSE provides notice pursuant to paragraph (a) above of a physical limitation that will delay the RUC-committed Resource's ability to reach its LSL in accordance with a RUC Dispatch Instruction, ERCOT shall extend the RUC Dispatch Instruction so that the Resource's minimum run time is respected. However, if the Resource will not be available in time to address the issue for which it received the RUC instruction, ERCOT may instead cancel the RUC Dispatch Instruction.

(5) A QSE shall be excused from complying with any portion of a RUC Dispatch Instruction that it could not meet due to a physical limitation that was reflected, at the time of the RUC Dispatch Instruction, in the Resource's COP, startup time, minimum On-Line time, or minimum Off-Line time.

(6) To determine the projected energy output level of each Resource and to project potential congestion patterns for each hour of the RUC, ERCOT shall calculate proxy Energy Offer Curves based on the Mitigated Offer Caps (MOCs) for the type of Resource as specified in Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, for use in the RUC. Proxy Energy Offer Curves are calculated by multiplying the MOC by a constant selected by ERCOT from time to time that is no more than 0.10% and applying the cost for all Generation Resource output between High Sustained Limit (HSL) and LSL. The intent of this process is to minimize the effect of the proxy Energy Offer Curves on optimization.

(7) ERCOT shall use the RUC process to evaluate the need to commit Resources for which a QSE has submitted Three-Part Supply Offers and other available Off-Line Resources in addition to Resources that are planned to be On-Line during the RUC Study Period. All of the above commitment information must be as specified in the QSE's COP. For available Off-Line Resources with a cold start time of one hour or less that have not been

removed from special consideration under paragraph (9) below pursuant to paragraph (4) of Section 8.1.2, Current Operating Plan (COP) Performance Requirements, the Startup Offers and Minimum-Energy Offer from a Resource's Three-Part Supply Offer shall not be used in the RUC process.

(8) ERCOT shall create Three-Part Supply Offers for all Resources that did not submit a Three-Part Supply Offer, but are specified as available but Off-Line, excluding Resources with a Resource Status of EMR, in a QSE's COP. For such Resources, excluding available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (9) below pursuant to paragraph (4) of Section 8.1.2, ERCOT shall use in the RUC process 100% of any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as described specified in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, registered with ERCOT. Also, for Settlement purposes, ERCOT shall use any approved verifiable Startup Costs and verifiable minimum-energy cost for such Resources, or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and Generic Minimum-Energy Offer Cost.

(9) For all available Off-Line Resources having a cold start time of one hour or less and not removed from special consideration pursuant to paragraph (4) of Section 8.1.2, ERCOT shall scale any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as specified in Section 4.4.9.2.3 for use in the RUC process.

The above parameter is defined as follows:

Parameter	Unit	Current Value*
1HRLESSCOSTSCALING	Percentage	Maximum value of 100%
* The current value for the parameter(s) referenced in this table above will be recommended by the Technical Advisory Committee (TAC) and approved by the ERCOT Board. ERCOT shall update parameter value(s) on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(10) The RUC process must treat all Resource capacity providing Ancillary Service as unavailable for the RUC Study Period, unless that treatment leads to infeasibility (i.e., that capacity is needed to resolve some local transmission problem that cannot be resolved by any other means). If an ERCOT Operator decides that the Ancillary Service capacity allocated to that Resource is infeasible based on ERCOT System conditions, then, ERCOT shall inform each affected QSE of the amount of its Resource capacity that does not qualify to provide Ancillary Service, and the projected hours for which this is the case. In that event, the affected QSE may, under Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints, either:

(a) Substitute capacity from Resources represented by that QSE;

(b) Substitute capacity from other QSEs using Ancillary Service Trades; or

(c) Ask ERCOT to replace the capacity.

(11) Factors included in the RUC process are:

(a) ERCOT System-wide hourly Load forecast allocated appropriately over Load buses;

(b) Transmission constraints – Transfer limits on energy flows through the electricity network;

(i) Thermal constraints – protect transmission facilities against thermal overload;

(ii) Generic constraints – protect the transmission system against transient instability, dynamic instability or voltage collapse;

(c) Planned transmission topology;

(d) Energy sufficiency constraints;

(e) Inputs from the COP, as appropriate;

(f) Inputs from Resource Parameters, including a list of Off-Line Available Resources having a start-up time of one hour or less, as appropriate;

(g) Each Generation Resource's Minimum-Energy Offer and Startup Offer, from its Three-Part Supply Offer;

(h) Any Generation Resource that is Off-Line and available but does not have a Three-Part Supply Offer;

(i) Forced Outage information; and

(j) Inputs from the eight-day look ahead planning tool, which may potentially keep a unit On-Line (or start a unit for the next day) so that a unit minimum duration between starts does not limit the availability of the unit (for security reasons).

(12) The HRUC process and the DRUC process are as follows:

(a) The HRUC process uses current Resource Status for the initial condition for the first hour of the RUC Study Period. All HRUC processes use the projected status of transmission breakers and switches starting with current status and updated for each remaining hour in the study as indicated in the COP for Resources and in the Outage Scheduler for transmission elements.

(b) The DRUC process uses the Day-Ahead forecast of total ERCOT Load including DC Tie Schedules for each hour of the Operating Day. The HRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules for each hour in the RUC Study Period.

(c) The DRUC process uses the Day-Ahead weather forecast for each hour of the Operating Day. The HRUC process uses the weather forecast information for each hour of the balance of the RUC Study Period.

(13) A QSE that has one or more of its Resources RUC-committed to provide Ancillary Services must increase its Ancillary Service Supply Responsibility by the total amount of RUC-committed Ancillary Service quantities. The QSE may only use a RUC-committed Resource to meet its Ancillary Service Supply Responsibility during that Resource's RUC-Committed Interval if the Resource has been committed by the RUC process to provide Ancillary Service, or the Resource is a Combined Cycle Generation Resource that was RUC-committed to transition from one On-Line configuration to a different configuration with additional capacity. For cases in which the commitment was to provide Ancillary Service, the QSE shall indicate the exact amount and type of Ancillary Service for which it was committed as the Resource's Ancillary Service Resource Responsibility and Ancillary Services Schedule for the RUC-Committed Intervals for both telemetry and COP information provided to ERCOT. Upon deployment of the Ancillary Services, the QSE shall adjust its Ancillary Services Schedule to reflect the amounts requested in the deployment.

(14) A QSE with a Resource that is not a Reliability Must-Run (RMR) Unit or has not received an Outage Schedule Adjustment (OSA) that has been committed in a DRUC or HRUC process may opt out of the RUC Settlement (or "buy back" the commitment) by setting the COP status of the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. All the configurations of the same Combined Cycle Train shall be treated as the same Resource for the purpose of creating the block of RUC-Committed Hours. A RUC-committed Combined Cycle Generation Resource may opt out of the RUC Settlement by setting the COP status of any Combined Cycle Generation Resource within the same Combined Cycle Train as the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. A Combined Cycle Generation Resource that is RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity may opt out of the RUC Settlement following the same rule for RUC-committed Combined Cycle Generation Resources described above. A QSE that opts out of RUC Settlement forfeits RUC Settlement for the affected Resource for a given block of RUC Buy-Back Hours. A QSE that opts out of RUC Settlement treatment must make the Resource available to SCED for all RUC Buy-Back Hours. All hours in a contiguous block of RUC-Committed Hours that includes the RUC Buy-Back Hour shall be considered RUC Buy-Back Hours. If a contiguous block of RUC-Committed Hours spans more than one Operating Day and a QSE wishes to opt out of RUC Settlement for the RUC-Committed Hours in the second or subsequent Operating Day, the QSE must set its COP status to

ONOPTOUT for the first hour of the first Operating Day in the Opt Out Snapshot of the first Operating Day.

(15) ERCOT shall, as soon as practicable, post to the ~~MIS Secure Area~~ERCOT website a report identifying those hours that were considered RUC Buy-Back Hours, along with the name of each RUC-committed Resource whose QSE opted out of RUC Settlement.

(16) A Resource that has a Three-Part Supply Offer cleared in the Day-Ahead Market (DAM) and subsequently receives a RUC commitment for the Operating Hour for which it was awarded will be treated as if the telemetered Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Security Constrained Economic Dispatch, and Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder.

(17) A Resource that has self-committed for an Operating Hour after the RUC Snapshot was taken but before the RUC commitment has been communicated through an XML message for that RUC process and that Operating Hour is included in a block of RUC-committed hours for that RUC process will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Section 6.5.7.3.1, Operating Reserve Demand Curve (ORDC) calculations, and RUC Settlement for the entire block of RUC-committed hours. A QSE that has a Resource that meets these conditions must make the Resource available to SCED for the entire block of RUC-committed hours. ERCOT will send the QSE a notification stating the Operating Day and block of hours for which this occurred.

[NPRR1009, NPRR1032, and NPRR1204: Replace applicable portions of Section 5.5.2 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1009 and NPRR1204; or upon system implementation for NPRR1032:]

5.5.2 Reliability Unit Commitment (RUC) Process

(1) The RUC process recommends commitment of Generation Resources, to match ERCOT's forecasted Load including Direct Current Tie (DC Tie) Schedules and RUC Ancillary Service Demand Curves (ASDCs), subject to all transmission constraints and Resource performance characteristics. The RUC process takes into account Resources already committed in the Current Operating Plans (COPs), Resources already committed in previous RUCs, and Off-Line Available Resources having a start-up time of one hour or less. For On-Line Energy Storage Resources (ESRs), using RUC duration requirements for energy and Ancillary Services, RUC-projected dispatch for energy and Ancillary Service in one interval shall respect the ESR's minimum and maximum State of Charge (SOC) values from the COP, while incorporating any adjustments under paragraph (18)(d) below. In addition, using the Ancillary Service Deployment Factors and their respective deployment duration requirements, the SOC required to support these dispatch levels for energy and Ancillary Services will match as closely as possible the difference between the adjusted COP values of the next interval's Hour Beginning Planned SOC and the current interval's Hour Beginning

Planned SOC. The formulation of the RUC objective function must employ penalty factors on violations of security constraints and violations of ESR COP Hour Beginning Planned SOC. The objective of the RUC process is to minimize costs based on the Resource costs described in paragraphs (10) through (14) below. ESR energy dispatch costs and Ancillary Service Offer costs are not included in the RUC objective function.

(2) ERCOT shall create an ASDC for each Ancillary Service for use in RUC. ERCOT shall post the ASDCs to the ERCOT website as soon as practicable after any change to the ASDCs.

(3) ERCOT shall post the following Ancillary Service Deployment Factor data on the ERCOT website:

(a) Following each execution of RUC, ERCOT shall post the Ancillary Service Deployment Factors used by that RUC process for each hour in the RUC Study Period;

(b) No later than 0600 in the Day-Ahead for each Operating Day, ERCOT shall post the Ancillary Service Deployments Factors that are projected to be used in the RUC process for that Operating Day; and

(c) Following each month, ERCOT shall post the average, minimum, and maximum Ancillary Service Deployment Factors used in the RUC process by type of Ancillary Service and hour of the day for the month.

(4) For all hours of the RUC Study Period within the RUC process, Quick Start Generation Resources (QSGRs) with a COP Resource Status of OFFQS shall be considered as On-Line with Low Sustained Limit (LSL) at zero MW. QSGRs with a Resource Status of OFFQS shall only be committed by ERCOT through a RUC instruction in instances when a reliability issue would not otherwise be managed through Dispatch Instructions from Security-Constrained Economic Dispatch (SCED).

(5) In addition to On-Line qualified Resources, the RUC engine shall consider a COP Resource status of OFFQS for QSGRs that are qualified for ERCOT Contingency Reserve Service (ECRS), as being eligible to provide ECRS constrained by the Ancillary Service capability in the COP.

(6) In addition to On-Line qualified Resources, the RUC engine shall consider a COP Resource Status of OFFQS for QSGRs that are qualified for Non-Spinning Reserve (Non-Spin), as being eligible to provide Non-Spin constrained by the Ancillary Service Capability in the COP. The RUC engine shall also consider a COP Resource Status of OFF (Off-Line but available for commitment in the DAM and RUC) for a Resource that is qualified for Non-Spin, as being eligible to provide Non-Spin constrained by the Ancillary Service capability in the COP.

(7) The RUC process can recommend Resource decommitment. ERCOT may only decommit a Resource to resolve transmission constraints that are otherwise

unresolvable. Qualifying Facilities (QFs) may be decommitted only after all other types of Resources have been assessed for decommitment. In addition, the HRUC process provides decision support to ERCOT regarding a Resource decommitment requested by a Qualified Scheduling Entity (QSE).

(8) ERCOT shall review the RUC-recommended Resource commitments and the list of Off-Line Available Resources having a start-up time of one hour or less to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. During the RUC process, ERCOT may also review and commit, through a RUC instruction, Combined Cycle Generation Resources that are currently planned to be On-Line but are capable of transitioning to a configuration with additional capacity. ERCOT may deselect Resources recommended in DRUC and in all HRUC processes if in ERCOT's sole discretion there is enough time to commit those Resources in the future HRUC processes, taking into account the Resources' start-up times, to meet ERCOT System reliability. After each RUC run, ERCOT shall post the amount of capacity deselected per hour in the RUC Study Period to the ~~MIS Secure Area~~ERCOT website. A Generation Resource shown as On-Line and available for SCED dispatch for an hour in its COP prior to a DRUC or HRUC process execution, according to Section 5.3, ERCOT Security Sequence Responsibilities, will be considered self-committed for that hour. For purpose of Settlement, snapshot data will be used as specified in paragraph (2) of Section 5.3.

(9) ERCOT shall issue RUC instructions to each QSE specifying its Resources that have been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the ~~MIS Secure Area~~ ERCOT website any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.

(10) ERCOT shall use the RUC process to evaluate the need to commit Resources for which a QSE has submitted Three-Part Supply Offers and other available Off-Line Resources in addition to Resources that are planned to be On-Line during the RUC Study Period. All of the above commitment information must be as specified in the QSE's COP. For available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (16) below pursuant to paragraph (4) of Section 8.1.2, Current Operating Plan (COP) Performance Requirements, the Startup Offers and Minimum-Energy Offer from a Resource's Three-Part Supply Offer shall not be used in the RUC process.

(11) ERCOT shall create Three-Part Supply Offers for all Resources that did not submit a Three-Part Supply Offer, but are specified as available but Off-Line, excluding Resources with a Resource Status of EMR, in a QSE's COP. For such Resources, excluding available Off-Line Resources with a cold start time of one hour or less that have not been removed from special consideration under paragraph (14) below pursuant to paragraph (4) of Section 8.1.2, ERCOT shall use in the RUC process 100% of any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer

Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as described specified in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, registered with ERCOT. Also, for Settlement purposes, ERCOT shall use any approved verifiable Startup Costs and verifiable minimum-energy cost for such Resources, or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and Generic Minimum-Energy Offer Cost.

(12) A QSE shall notify the ERCOT Operator of any physical limitation that impacts its Resource's ability to start that is not reflected in the Resource's COP or the Resource's startup time, minimum On-Line time, or minimum Off-Line time. The following shall apply:

(a) If a Resource receives a RUC Dispatch Instruction that it cannot meet due to a physical limitation described in paragraph (5) above, the QSE representing the Resource shall notify the ERCOT Operator of the inability to fully comply with the instruction and shall comply with the instruction to the best of the Resource's ability. If the QSE has provided the ERCOT Operator notice of that limitation at least seven days prior to the Operating Day in which the instruction occurs, the QSE shall be excused from complying with the portion of the RUC Dispatch Instruction that it could not meet due to the identified limitation.

(b) If a QSE provides notice pursuant to paragraph (a) above of a physical limitation that will delay the RUC-committed Resource's ability to reach its LSL in accordance with a RUC Dispatch Instruction, ERCOT shall extend the RUC Dispatch Instruction so that the Resource's minimum run time is respected. However, if the Resource will not be available in time to address the issue for which it received the RUC instruction, ERCOT may instead cancel the RUC Dispatch Instruction.

(13) A QSE shall be excused from complying with any portion of a RUC Dispatch Instruction that it could not meet due to a physical limitation that was reflected, at the time of the RUC Dispatch Instruction, in the Resource's COP, startup time, minimum On-Line time, or minimum Off-Line time.

(14) To determine the projected energy output level of each Resource and to project potential congestion patterns for each hour of the RUC, ERCOT shall calculate proxy Energy Offer Curves based on the Mitigated Offer Caps (MOCs) for the type of Resource as specified in Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, for use in the RUC. Proxy Energy Offer Curves are calculated by multiplying the MOC by a constant selected by ERCOT from time to time that is no more than 0.10% and applying the cost for all Generation Resource output between High Sustained Limit (HSL) and LSL. The intent of this process is to minimize the effect of the proxy Energy Offer Curves on optimization. For ESRs, energy dispatch costs are not considered in determining projected energy output levels.

(15) ERCOT shall calculate proxy Ancillary Service Offer Curves for use in RUC based on validated Ancillary Service Offers as specified in Section 4.4.7.2, Ancillary Service

Offers. For all Resources that do not have a valid Ancillary Service Offer but are qualified to provide an Ancillary Service, ERCOT shall create an Ancillary Service Offer Curve for use in RUC as described in Section 6.5.7.3, Security Constrained Economic Dispatch. Proxy Ancillary Service Offer Curves for use in RUC are calculated by multiplying the Ancillary Service Offer by a constant selected by ERCOT from time to time that is no more than 0.1%, and are extended between the HSL and LSL. Notwithstanding the presence or absence of a proxy Ancillary Service Offer, Ancillary Service provision in RUC shall be limited by the Resource's Ancillary Service capabilities as reflected in the COP. For ESRs, Ancillary Service Offer costs are not considered in determining projected Ancillary Service awards.

(16) For all available Off-Line Resources having a cold start time of one hour or less and not removed from special consideration pursuant to paragraph (4) of Section 8.1.2, ERCOT shall scale any approved verifiable Startup Cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as specified in Section 4.4.9.2.3 for use in the RUC process.

The above parameter is defined as follows:

Parameter	Unit	Current Value*
1HRLESSCOSTSCALING	Percentage	Maximum value of 100%

* The current value for the parameter(s) referenced in this table above will be recommended by the Technical Advisory Committee (TAC) and approved by the ERCOT Board. ERCOT shall update parameter value(s) on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.

(17) Factors included in the RUC process are:

(a) ERCOT System-wide hourly Load forecast allocated appropriately over Load buses;

(b) ERCOT's Ancillary Service Plans in the form of ASDCs;

(c) Transmission constraints – Transfer limits on energy flows through the electricity network;

(i) Thermal constraints – protect transmission facilities against thermal overload;

(ii) Generic constraints – protect the transmission system against transient instability, dynamic instability or voltage collapse;

(d) Planned transmission topology;

(e) Energy sufficiency constraints, including RUC duration requirements for energy and Ancillary Services;

(f) Inputs from the COP, as appropriate;

(g) Inputs from Resource Parameters, including a list of Off-Line Available Resources having a start-up time of one hour or less, as appropriate;

(h) Each Generation Resource's Minimum-Energy Offer and Startup Offer, from its Three-Part Supply Offer;

(i) Any Generation Resource that is Off-Line and available but does not have a Three-Part Supply Offer;

(j) Forced Outage information;

(k) Inputs from the eight-day look ahead planning tool, which may potentially keep a unit On-Line (or start a unit for the next day) so that a unit minimum duration between starts does not limit the availability of the unit (for security reasons); and

(l) Ancillary Service Deployment Factors.

(18) The HRUC process and the DRUC process are as follows:

(a) The HRUC process uses current Resource Status for the initial condition for the first hour of the RUC Study Period. All HRUC processes use the projected status of transmission breakers and switches starting with current status and updated for each remaining hour in the study as indicated in the COP for Resources and in the Outage Scheduler for transmission elements.

(b) The DRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules up to the physical rating of the DC Tie for each hour of the Operating Day. The HRUC process uses the current hourly forecast of total ERCOT Load including DC Tie Schedules up to the physical rating of the DC Tie for each hour in the RUC Study Period.

(c) The DRUC process uses the Day-Ahead weather forecast for each hour of the Operating Day. The HRUC process uses the weather forecast information for each hour of the balance of the RUC Study Period.

(d) For the HRUC, DRUC, and Weekly Reliability Unit Commitment (WRUC) processes, a feasibility check on the COP submitted Hour Beginning Planned SOC will be performed. This check may adjust the Hour Beginning Planned SOC used in the RUC process. The feasibility check looks sequentially across all intervals in the RUC Study Period to validate whether a particular interval's COP Hour Beginning Planned SOC is achievable from the previous interval. If

it is not feasible, then RUC will adjust the Hour Beginning Planned SOC to the closest achievable value.

(19) A QSE with a Resource that is not a Reliability Must-Run (RMR) Unit or has not received an Outage Schedule Adjustment (OSA) that has been committed in a DRUC or HRUC process may opt out of the RUC Settlement (or "buy back" the commitment) by setting the COP status of the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. All the configurations of the same Combined Cycle Train shall be treated as the same Resource for the purpose of creating the block of RUC-Committed Hours. A RUC-committed Combined Cycle Generation Resource may opt out of the RUC Settlement by setting the COP status of any Combined Cycle Generation Resource within the same Combined Cycle Train as the RUC-committed Resource to ONOPTOUT for the first hour of a contiguous block of RUC-Committed Hours in the Opt Out Snapshot. A Combined Cycle Generation Resource that is RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity may opt out of the RUC Settlement following the same rule for RUC-committed Combined Cycle Generation Resources described above. A QSE that opts out of RUC Settlement forfeits RUC Settlement for the affected Resource for a given block of RUC Buy-Back Hours. A QSE that opts out of RUC Settlement treatment must make the Resource available to SCED for all RUC Buy-Back Hours. All hours in a contiguous block of RUC-Committed Hours that includes the RUC Buy-Back Hour shall be considered RUC Buy-Back Hours. If a contiguous block of RUC-Committed Hours spans more than one Operating Day and a QSE wishes to opt out of RUC Settlement for the RUC-Committed Hours in the second or subsequent Operating Day, the QSE must set its COP status to ONOPTOUT for the first hour of that the first Operating Day in the Opt Out Snapshot of the first Operating Day.

(20) ERCOT shall, as soon as practicable, post to the ~~MIS Secure Area~~ERCOT website a report identifying those hours that were considered RUC Buy-Back Hours, along with the name of each RUC-committed Resource whose QSE opted out of RUC Settlement.

(21) A Resource that has a Three-Part Supply Offer cleared in the Day-Ahead Market (DAM) and subsequently receives a RUC commitment for the Operating Hour for which it was awarded will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3 and Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders.

(22) A Resource that has self-committed for an Operating Hour after the RUC Snapshot was taken but before the RUC commitment has been communicated through an XML message for that RUC process and that Operating Hour is included in a block of RUC-committed hours for that RUC process will be treated as if the Resource Status was ONOPTOUT for purposes of Section 6.5.7.3, Section 6.5.7.3.1, Operating Reserve Demand Curve (ORDC) calculations, and RUC Settlement for the entire block of RUC-committed hours. A QSE that has a Resource that meets these conditions must make the Resource available to SCED for the entire block of RUC-committed hours. ERCOT

will send the QSE a notification stating the Operating Day and block of hours for which this occurred.

5.7.4 RUC Make-Whole Charges

(1) All QSEs that were capacity-short in each RUC will be charged for that shortage, as described in Section 5.7.4.1, RUC Capacity-Short Charge. If the revenues from the charges under Section 5.7.4.1 are not enough to cover all RUC Make-Whole Payments for a Settlement Interval, then the difference will be uplifted to all QSEs on a Load Ratio Share (LRS) basis, as described in Section 5.7.4.2, RUC Make-Whole Uplift Charge.

(2) On a monthly basis, within ten days after the Initial Settlement of the last day of the month has been completed, ERCOT shall post on the ~~Market Information System (MIS) Secure Area~~ERCOT website the total RUC Make-Whole Charges and RUC Clawback Payment Amounts, by Settlement Interval, by QSE capacity-shortfall and by amount uplifted.

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

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

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

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

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

(i) Transmission Electrical Bus voltages;

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

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

(iv) Tap position for auto-transformers;

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

(c) Transmission Element ratings from TSPs;

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

(c) Transmission Element ratings from TSPs and DCTOs;

(i) Data from the Network Operations Model:

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

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

(ii) Data from QSEs:

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

(B) Resource HSL (from telemetry); and

(C) Resource LSL (from telemetry); and

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

[NPRR857: Replace paragraph (d) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

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

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

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

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

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

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

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

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

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

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

(e) Operator summary displays:

(i) Transmission system status changes;

(ii) Overloads;

(iii) System security violations; and

(iv) Base Points.

(4) Every hour, ERCOT shall post on the MIS Secure Area, except where otherwise stated in this Section 6.5.7.1.13(4), the following information:

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

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

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

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

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

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

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

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

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

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

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

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

6.5.7.6.2.1 Deployment of Regulation Service

(1) ERCOT shall deploy Reg-Up and Reg-Down necessary to maintain ERCOT System frequency to meet NERC Control Area and other Control Area performance criteria as specified in these Protocols and the Operating Guides.

(2) Reg-Up is a deployment or recall of a deployment referenced to the Resource's Base Point in response to a change (up or down) in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

(3) Reg-Down is a deployment or recall of a deployment referenced to the Resource's Base Point in response to a change (up or down) in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

(4) These requirements also apply to the deployment or recall of a deployment of Reg-Up and Reg-Down:

(a) Deployment or recall of a deployment must be accomplished through use of an automatic signal from ERCOT to each QSE provider of Reg-Up and Reg-Down.

(b) ERCOT shall minimize Reg-Up and Reg-Down energy as much as practicable in each SCED cycle.

(c) ERCOT shall settle energy provided by Reg-Up and Reg-Down at the Resource's Settlement Point Price.

(d) ERCOT shall integrate the control signal sent to providers of Reg-Up and shall calculate the amount of energy deployed by Reg-Up in each Settlement Interval.

(e) ERCOT shall integrate the control signal sent to providers of Reg-Down and shall calculate the amount of energy deployed by Reg-Down in each Settlement Interval.

(f) ERCOT shall calculate for each LFC cycle the amount of regulation that each Resource is expected to provide at that instant in time. The expected amount must be averaged over each SCED interval. The actual generation from telemetry must also be averaged over each SCED interval.

(5) Every day, ERCOT shall post to the ~~MIS Secure Area~~ERCOT website the total amount of deployed Reg-Up and Reg-Down energy in each Settlement Interval of the previous day.

(6) For each Resource providing Reg-Up or Reg-Down, the implied ramp rate in MW per minute is the total amount of Regulation Service awarded divided by five.

(7) Each QSE providing Reg-Up or Reg-Down and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring.

(8) ERCOT shall issue Reg-Up and Reg-Down deployment Dispatch Instructions over ICCP. Those Dispatch Instructions must contain the change in MW output requested of the QSE assuming all Resources are at their Updated Desired Base Point issued by LFC.

[NPRR1010: Replace paragraph (8) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(8) ERCOT shall issue Reg-Up and Reg-Down deployment Dispatch Instructions over ICCP. Those Dispatch Instructions must contain the change in MW output requested of the Resource.

(9) Reg-Up and Reg-Down Dispatch Instructions shall be included as a component of a Resource's UDSP.

(10) Upon the receipt of new Base Points and Ancillary Service awards from SCED, LFC will reset Regulation Service instructions to zero.

6.5.9.5.1 Registration and Posting of BLT Points

(1) The necessary Market Participant registration, agreements, metering, and ERCOT Settlement systems, as applicable, must be in place before implementation of any BLT. At its sole discretion, ERCOT may exclude a BLT of ten MW or less from the Network Operations Model and associated telemetry requirements.

(2) ERCOT may require any size of BLT that has been deployed in accordance with Section 6.5.9.5.2, Scheduling and Operation of BLTs, to be in the Network Operations Model with required telemetry if ERCOT determines it is warranted due to the length of time deployed.

(3) BLTs that transfer Load from the ERCOT Control Area to a non-ERCOT Control Area are treated as generation and Load by ERCOT and assigned a Resource ID and, if in a NOIE territory, an ESI ID unless the Load is in a NOIE territory and the NOIE has not registered the BLT for Settlement pursuant to paragraph (1)(g) of Section 6.5.9.5, Block Load Transfers between ERCOT and Non-ERCOT Control Areas. The ERCOT Control Area TSP or DSP associated with the BLT Point has the responsibility for registering the BLT and the creation and maintenance of BLT Resource IDs for Settlement purposes. For any BLT that a NOIE has registered for Settlement, the NOIE shall designate NOIE metering point(s), a Resource Entity, and a QSE for Settlement purposes. For BLTs occurring on TSP or DSP systems open to Customer Choice, the non-ERCOT Control Area Entity receiving the transferred Load shall designate a registered Resource Entity and acknowledge a QSE for Settlement purposes in accordance with Section 16.5, Registration of a Resource Entity. The ERCOT Control Area TSP or DSP must complete

the applicable BLT registration form. This BLT registration form along with the metering design and data documentation is the basis for establishing the ERCOT data model of the BLT and associated metering points for Settlement as applicable.

(4) BLTs that transfer Load from a non-ERCOT Control Area to the ERCOT Control Area are treated as a non-competitive wholesale Load by ERCOT and assigned an ESI ID unless the BLT is in a NOIE territory and the NOIE has not registered the BLT for Settlement. The ERCOT Control Area TSP or DSP associated with the BLT Point has the responsibility for registering the BLT and the creation and maintenance of BLT ESI IDs. Customers connected to the ERCOT System do not require an ESI ID separate from the assigned BLT ESI ID. The TSP or DSP that registers the BLT Point shall provide the ESI ID associated with the BLT to ERCOT. For BLTs occurring on NOIE TSP or DSP systems, the NOIE may designate NOIE metering point(s), an LSE, and a QSE for Settlement purposes. Load associated with NOIE BLTs that do not have an LSE or QSE for Settlement purposes will be reflected in the NOIE's 4-Coincident Peak (4-CP) calculation. For BLTs occurring on TSP or DSP systems open to Customer Choice, the non-ERCOT Control Area Entity shall designate a registered ERCOT LSE and acknowledge a QSE for Settlement purposes in accordance with Section 16.3, Registration of Load Serving Entities.

(5) A "BLT Point" is the metering point for a BLT Resource ID or for a BLT ESI ID.

(6) ERCOT shall post the registration details of all registered BLTs to the ~~MIS Secure Area~~ERCOT website.

8.1 QSE and Resource Performance Monitoring

(1) ERCOT shall develop a Technical Advisory Committee (TAC)- and ERCOT Board-approved Qualified Scheduling Entity (QSE) and Resource monitoring program to be included in the Operating Guides. Nothing in this Section changes the process for amending the Operating Guides. The metrics developed by ERCOT and approved by TAC and the ERCOT Board must include the provisions of this Section.

(2) Each QSE and Resource shall meet performance measures as described in this Section and in the Operating Guides.

(3) ERCOT shall monitor and post the following categories of performance:

(a) Real-Time data, for QSEs:

(i) Telemetry performance

(b) Regulation control performance, for QSEs and as applicable, Resource-specific performance (see also Section 8.1.1, QSE Ancillary Service Performance Standards);

(c) Hydro responsive testing for Generation Resources, on the ERCOT website;

(d) Supplying and validating data for generator models, as requested by ERCOT, for Generation Resources;

(e) Outage scheduling and coordination, for QSEs and Resources;

(f) Resource-specific Responsive Reserve (RRS) performance for QSEs and Resources, on the ERCOT website;

(g) Resource-specific Non-Spinning Reserve (Non-Spin) performance, for QSEs and Resources, on the ERCOT website;

(h) Resource-specific ERCOT Contingency Reserve Service (ECRS) performance for QSEs and Resources, on the ERCOT website ;

(i) Outage reporting, by QSEs for Resources;

(j) Current Operating Plan (COP) metrics, for QSEs, on the ERCOT website; and

(k) Day-Ahead Reliability Unit Commitment (DRUC) and Hourly Reliability Unit Commitment (HRUC) commitment performance by QSEs and Generation Resources, on the ERCOT website.

8.1.2 Current Operating Plan (COP) Performance Requirements

(1) Each QSE representing a Resource must submit a COP in accordance with Section 3.9, Current Operating Plan (COP).

(2) For each QSE, ERCOT shall post on the ERCOT website for each month the number, by Operating Hour, of valid COP failures to meet the provisions of paragraphs (3) and (4) of Section 3.9.2, Current Operating Plan Validation, for Ancillary Service Resource Responsibilities contained in the QSE's COP used for the DRUC and each HRUC during the Operating Day. QSEs shall have no more than three hours during an Operating Day or 74 hours during a month that contains COP Ancillary Service Resource Responsibility validation failures.

[NPRR1011: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(3) For each QSE, ERCOT shall post on the ERCOT website for each month the number of Operating Hours during which a Reliability Unit Commitment (RUC)-committed QSE Resource, not Off-Line as the result of a Forced Outage, failed to be On-Line and released to SCED for deployment within the first 15 minutes of the RUC-Commitment Hour. QSEs shall have no more than three hours during an Operating Day and no more than 74 hours during a month that contains one or more of these events.

(4) ERCOT shall post on the ERCOT website for each QSE for each month the number of Operating Hours during which a RUC-committed Resource with a cold start time of one hour or less, not Off-Line as the result of a Forced Outage, failed to be On-Line and released to SCED (has reached its physical LSL) within its cold start time by the start of the Operating Hour for which it was RUC-committed. Any Resource with more than one occurrence during a month whereby the cold start time is not met shall be removed from special consideration pursuant to paragraph (7) of Section 5.5.2, Reliability Unit Commitment (RUC) Process, for a period of 90 days, beginning with the next Operating Day following the second occurrence within a month.

8.5.1.2 Reporting

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

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

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

[NPRR995: Replace paragraph (3) above with the following upon system implementation:]

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

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

9.14.4 ERCOT Processing of Disputes

(1) ERCOT shall process disputes in accordance with this Section, Section 9.14.2, Notice of Dispute, and the required data in Section 9.14.3, Contents of Notice.

(2) If ERCOT requires additional data to resolve the dispute, ERCOT shall send the Settlement Statement Recipient or Invoice Recipient a list of the required additional data within seven Business Days of the date the dispute was filed. The Settlement Statement

Recipient or Invoice Recipient shall respond with the entire set of required data within five Business Days of ERCOT's request or by a date agreed upon by ERCOT and the Market Participant that is no later than eight Business Days prior to the posting of the True-Up Settlement Statement for the disputed Operating Day. If ERCOT does not receive the data within that time frame, ERCOT shall deny the dispute.

(3) On each Business Day, ERCOT shall issue an aggregated Settlement and billing dispute resolution report on the ~~MIS Secure Area~~ERCOT website containing information related to all disputes that are not yet closed or that have been closed recently. Additionally, on each Business Day and for each Settlement Statement Recipient or Invoice Recipient, ERCOT shall issue a report on the MIS Certified Area containing the status of each submitted dispute. The report shall identify the disputed charge type(s), status of the dispute, resolution and resolution date, if applicable, and a financial impact in dollars of the dispute as submitted by disputing Entity.

(4) ERCOT shall make all reasonable attempts to complete all RTM Settlement and billing disputes submitted within 15 Business Days of the issuance of the RTM Initial Statement in time for inclusion on the RTM Final Statement for the relevant Operating Day.

(5) All complete disputes of the DAM received within ten Business Days after ERCOT posts that day's DAM Settlement Statement shall be included in a Resettlement of the DAM Operating Day under Section 9.2.5, DAM Resettlement Statement.

(6) For Settlement and billing disputes requiring complex research or additional time for resolution, ERCOT shall notify the Invoice Recipient or Settlement Statement Recipient of the length of time expected to research and resolve those disputes and, if ERCOT grants a portion or all of the dispute, ERCOT shall post the necessary adjustments on the next available Settlement Statement for the Operating Day.

(7) Settlement Statement Recipients or Invoice Recipients have the right to proceed to the ADR process in Section 20, Alternative Dispute Resolution Procedure and Procedure for Return of Settlement Funds, for filed disputes that cannot be resolved through the Settlement and billing dispute process outlined in Section 9.14, Settlement and Billing Dispute Process.

(8) All complete disputes of the CRR Market received within ten Business Days after ERCOT posts that day's CRR Settlement Statement shall be resolved as soon as practicable.

9.14.4.1.6 ADR

(1) Requests for ADR shall be considered Protected Information in accordance with paragraph (1)(ff) of Section 1.3.1.1, Items Considered Protected Information, and Section 20, Alternative Dispute Resolution Procedure and Procedure for Return of Settlement Funds. As soon as practicable after ERCOT receives a written request for ADR pursuant to Section 20.4, Initiation of ADR Proceedings, ERCOT shall post a Settlement and billing dispute status of "ADR" to the aggregated Settlement and billing dispute resolution report on the ~~MIS Secure Area~~ERCOT website. The dispute will remain in the

ADR status as long as the Market Participant has an active ADR. At the end of the ADR process, ERCOT shall post a Settlement and billing dispute status of "Closed" to the aggregated Settlement and billing dispute resolution report on the ~~MIS Secure Area~~ERCOT website.

9.19 Partial Payments by Invoice Recipients

(1) If at least one Invoice Recipient owing funds does not pay its Settlement Invoice in full (short-pay), ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient prior to four hours preceding the close of the Bank Business Day Central Prevailing Time (CPT) on the day that payments by ERCOT are due to be paid to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available Financial Security pledged to ERCOT by each short-paying Invoice Recipient that did not pay the amount due under paragraph (a) above. If the amount of any such draw is greater than the amount of the short-paying Invoice Recipient's cash collateral held in excess of that required to cover its Total Potential Exposure (TPE) ("Excess Collateral"), then a draw on available security for a short-paying Invoice Recipient shall be considered a Late Payment for purposes of Section 16.11.6, Payment Breach and Late Payments by Market Participants. ERCOT may, in its sole discretion, hold up to 5% of Financial Security of each short-paying Invoice Recipient and use those funds to pay subsequent Settlement Invoices as they become due. Any funds still held will be applied to unpaid Invoices in conjunction with the default uplift process outlined in Section 9.19.1, Default Uplift Invoices.

(c) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT to a short-paying Invoice Recipient against amounts not paid by that Invoice Recipient, and ERCOT shall apply the amount offset or recouped to cover short pays by that Invoice Recipient. ERCOT may, in its sole discretion, hold credit Invoices and use those funds to pay subsequent Settlement Invoices as they become due. Any funds still held will be offset or recouped against unpaid Invoices in conjunction with the default uplift process outlined in Section 9.19.1.

(d) If, after taking the actions set forth in paragraphs (a), (b) and (c) above, ERCOT still does not have sufficient funds to pay all amounts that it owes to Settlement Invoice Recipients in full, ERCOT shall deduct any applicable administrative fees as specified in Section 9.16, ERCOT System Administration and User Fees, payments for Reliability Must-Run (RMR) Services, and the Congestion Revenue Right (CRR) Balancing Account (CRRBA) from the amount received or collected and then reduce payments to all Settlement Invoice Recipients owed monies from ERCOT. The reductions must be based on a pro rata basis of monies owed to each Settlement Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short pays

and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the Settlement Invoice.

(e) If sufficient funds continue to be unavailable for ERCOT to pay all amounts in full to short-paid Entities for that Settlement Invoice and the short-paying Entity is not complying with a payment plan designed to enable ERCOT to pay all amounts in full to short-paid Entities, ERCOT shall uplift short-paid amounts through the Default Uplift process described below in Section 9.19.1 and Section 9.19.2, Payment Process for Default Uplift Invoices.

(f) When ERCOT enters into a payment plan with a short-pay Invoice Recipient, ERCOT shall post to the ~~Market Information System (MIS) Secure Area~~ERCOT website:

(i) The short-pay plan;

(ii) The schedule of quantifiable expected payments, updated if and when modifications are made to the payment schedule; and

(iii) Invoice dates to which the payments will be applied.

(g) To the extent ERCOT is able to collect past due funds owed by a short-paying Invoice Recipient before the default uplift process defined in Section 9.19.1, ERCOT shall allocate the collected funds to the earliest short-paid Invoice for that short-paying Invoice Recipient. ERCOT shall use its best efforts to distribute collected funds quarterly by the 15th Business Day following the end of a calendar quarter for a short paying Entity when the cumulative amount of undistributed funds held exceed $50,000 on a pro rata basis of monies owed. Subsequently collected funds that have not previously been distributed will be applied against unpaid Invoices in conjunction with the uplift process outlined in Section 9.19.1.

(h) To the extent ERCOT is able to collect past due funds owed by a short-paying Invoice Recipient, after the default uplift process defined in Section 9.19.1, ERCOT shall allocate the collected funds using the same allocation method as in the default uplift process. ERCOT shall use its best efforts to distribute subsequently collected funds quarterly by the 15th Business Day following the end of a calendar quarter for a short paying Entity when the cumulative amount of undistributed funds held exceed $50,000.

11.5.1.2 TSP and/or DSP Load Data Posting/Availability

(1) ERCOT shall post on the ERCOT website the following information, consistent with the requirements in Section 1.3, Confidentiality:

(a) ERCOT will post TSP and/or DSP Load plus allocation of Distribution Losses, Transmission Losses, and UFE, by TSP and/or DSP~~, to the MIS Secure Area~~.

(b) ~~(2)~~ ERCOT will make the aforementioned data for each Settlement run type available to Market Participants ~~via the MIS Secure Area~~ within 48 hours of finalizing the data for Settlement Statements.

(c) ~~(3)~~ ERCOT will post ~~to the MIS Secure Area,~~ a monthly report including TSP and/or DSP 15-minute interval Load data for each Operating Day adjusted to exclude Block Load Transfers (BLTs) or Direct Current Tie (DC Tie) exports.

11.5.2.2 General Public Data Posting/Availability

(1) The following general market information will be posted ~~to the MIS Secure Area~~ on the ERCOT website:

(a) Total generation;

(b) Total Adjusted Meter Load (AML); and

(c) Total Wholesale Storage Load (WSL).

(2) ERCOT will make the aforementioned data for each Settlement run type available to Market Participants via the MIS Certified Area within 48 hours of finalizing the data for Settlement statements.

12.3 MIS Administrative and Design Requirements

(1) The Market Information System (MIS) must comply with the administrative and design requirements specified as follows:

(a) ERCOT shall ensure that all Market Participants have access to the ERCOT MIS on a nondiscriminatory basis.

(b) The MIS must, at a minimum, provide all information required under any regulations of the Public Utility Commission of Texas (PUCT) or other Governmental Authorities.

(c) The ~~MIS~~ ERCOT website must include, consistent with the requirements in Section 1.3, Confidentiality, any available information that may be used by a Qualified Scheduling Entity (QSE) to estimate or verify bills for all ERCOT-provided settlements.

(d) ~~At the request of an Eligible Transmission Service Customer~~On the ERCOT website, ERCOT shall provide, consistent with the requirements in Section 1.3, the methodology and data to independently reproduce information contained in the MIS related to the operation of the ERCOT market.

(e) The MIS must include security measures to safeguard ERCOT Critical Energy Infrastructure Information (ECEII) and protect the confidentiality of Protected Information as required by these Protocols.

(f) The MIS must comply with industry standards for commercial websites, including query and search functionality.

(g) The MIS must provide easy navigation based on the posting list described in paragraph (4) of Section 12.2, ERCOT Responsibilities, above for document retrieval. This navigability must include hyperlinks between listings and the MIS posted information.

Revised ERCOT Impact Analysis Report

NPRR Number	1239	NPRR Title	Access to Market Information
Impact Analysis Date		October 29, 2024	
Estimated Cost/Budgetary Impact		Between $50k and $100k	
Estimated Time Requirements		The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 3 to 6 months	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Data Management & Analytic Systems 53% • ERCOT Website and MIS Systems 33% • Channel Management Systems 13%	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this NPRR.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NPRR Number	1240	NPRR Title	Access to Transmission Planning Information
Date of Decision		December 3, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Between $40k and $60k Project Duration: 3 to 6 months	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Priority – 2025; Rank – 4540	
Nodal Protocol Sections Requiring Revision		3.1.3.2, Resources 3.1.5.13, Transmission Report 3.1.8, High Impact Transmission Element (HITE) Identification 3.2.2, Demand Forecasts 3.10.2, Annual Planning Model 3.10.4, ERCOT Responsibilities 3.10.9.6, Telemetry and State Estimator Performance Monitoring 3.12, Load Forecasting 3.14.1, Reliability Must Run 3.15, Voltage Support 3.20.1, Evaluation of Chronic Congestion 6.3.1, Activities for the Adjustment Period 6.5.1.2, Centralized Dispatch	
Related Documents Requiring Revision/Related Revision Requests		Nodal Operating Guide Revision Request (NOGRR) 267, Related to NPRR1240, Access to Transmission Planning Information Planning Guide Revision Request (PGRR) 116, Related to NPRR1240, Access to Transmission Planning Information	
Revision Description		This Nodal Protocol Revision Request (NPRR) moves from the Market Information System (MIS) Secure Area to the public ERCOT website reports that do not contain ERCOT Critical Energy Infrastructure Information (ECEII). ERCOT Staff analyzed reports in the MIS Secure Area, along with existing Protocols for posting requirements, and identified no ongoing basis for holding in the MIS Secure Area reports determined to contain only Transmission planning information for a market audience and not ECEII.	

Board Report

	In addition to moving reports that do not contain ECEII to the ERCOT website, this NPRR also conforms rules with current posting practices for maintaining on the MIS Secure Area ECEII lists of equipment in the Outage Scheduler; for making available in the Model On Demand (MOD) application the annual planning model data submittal schedule; and for posting on the ERCOT website weekly Demand forecasts, demand analyses for 36 months and beyond, metrics of forecast error, and assessments of chronic congestion. This NPRR also clarifies that the Technical Advisory Committee (TAC) publicly reviews the Major Transmission Elements (MTE) list that isn't ECEII, rather than the High Impact Transmission Elements (HITE) list that is ECEII; that Private Use Network Load distribution factor data would be redacted from postings on the "ERCOT website" rather than on the "MIS"; and that ERCOT's monthly evaluations of chronic congestion are posted on the ERCOT website. Finally, this NPRR strikes the requirement to post on the ERCOT website shift schedules for ERCOT Operations Staff – currently, ERCOT posts shift schedules redacted of individuals' identifying information, making the postings of little or no public use.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	Reports that are not Protected Information in the MIS Secure Area are available to any registered Market Participant who requests a standard Digital Certificate from ERCOT; and paragraph (1)(j) of Section 1.3.1.2, Items Not Considered Protected Information, treats similarly requirements to post non-Protected Information on the ERCOT website or on the MIS Secure Area. This NPRR moves

	reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports that are not Protected Information without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request.
PRS Decision	On 7/18/24, PRS voted unanimously to table NPRR1240. All Market Segments participated in the vote. On 9/12/24, PRS voted unanimously to recommend approval of NPRR1240 as submitted. All Market Segments participated in the vote. On 10/17/24, PRS voted unanimously to table NPRR1240. On 11/14/24, PRS voted unanimously to endorse and forward to TAC the 10/17/24 PRS Report and 10/29/24 Revised Impact Analysis for NPRR1240 with a recommended priority of 2025 and a rank of 4540. All Market Segments participated in the vote.
Summary of PRS Discussion	On 7/18/24, ERCOT Staff presented NPRR1240. Some participants expressed concern for unintended consequences and requested additional time to review the language, and to consider use of the ERCOT website. On 9/12/24, participants noted ROS endorsement of NPRR1240. On 10/17/24, participants reviewed the 7/2/24 Impact Analysis. ERCOT Staff requested tabling NPRR1240to allow for additional internal review of the Impact Analysis. On 11/14/24, participants reviewed the 10/29/24 Revised Impact Analysis.
TAC Decision	On 11/20/24, TAC voted unanimously to recommend approval of NPRR1240 as recommended by PRS in the 11/14/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/20/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable)

Board Report

	☐ Other: (explain)
Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1240 as recommended by TAC in the 11/20/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1240 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1240.
ERCOT Opinion	ERCOT supports approval of NPRR1240.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1240 and believes it provides a positive market impact by improving access and transparency by moving reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request.

Sponsor	
Name	Kim Rainwater
E-mail Address	Kimberly.Rainwater@ercot.com
Company	ERCOT
Phone Number	512-225-7179
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com
Phone Number	512-225-7027

Comments Received

Board Report

Comment Author	Comment Summary
ROS 080224	Requested PRS continue to table NPRR1240
ROS 091024	Endorsed NPRR1240 as submitted

Market Rules Notes

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:

- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources (incorporated 12/1/24)
  Section 6.3.1

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

- NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
  - Section 3.15
- NPRR1246, Energy Storage Resource Terminology Alignment for Single-Model Era
  - Section 3.1.3.2
  - Section 3.14.1

Proposed Protocol Language Revision

3.1.3.2 Resources

Commented [EWG1]: Please note NPRR1246 also proposes changes to this section.

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

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

3.1.5.13 Transmission Report

(1) ERCOT shall post on the MIS Secure Area:

(a) Within one hour of receipt by ERCOT, all Transmission Facilities Outages that have been submitted into the ERCOT Outage Scheduler, excluding Private Use Network transmission Outages;

(b) Within one hour of a change of an Outage, all Transmission Facilities Outages, excluding Private Use Network transmission Outages;

(c) Once each day, Outage Scheduler notes related to the coordination of Outages;

(d) At least annually, an updated list of High Impact Transmission Elements (HITEs) pursuant to Section 3.1.8, High Impact Transmission Element (HITE) Identification; ~~and~~

(e) Once each day, list of TOOs submitted with 90-days or less notice that are accepted or approved~~.~~; and

(f) An updated list of current and future equipment in the Outage Scheduler by operator.

3.1.8 High Impact Transmission Element (HITE) Identification

(1) ERCOT, with input from Market Participants, shall develop a list of HITEs. ERCOT, with input from Market Participants, shall develop a list of Major Transmission Elements for review and approval at least annually by the TAC.

3.2.2 Demand Forecasts

(1) Monthly, ERCOT shall ~~develop~~ post on the ERCOT website the weekly peak hour Demand forecast for the ERCOT Region and for the Forecast Zones based on the 36-Month Load Forecast as described in Section 3.12, Load Forecasting, for the following 36 months, starting with the second week. During the development of this forecast, ERCOT may consult with Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs), and other Market Participants that may have knowledge of potential Load growth.

(2) ERCOT may, at its discretion, publish on the ~~MIS Secure Area~~ERCOT website, additional peak Demand analyses for periods beyond 36 months.

(3) ERCOT shall develop and publish hourly on the ERCOT website, peak Demand forecasts by Forecast Zone for each hour of the next seven days using the Seven-Day Load Forecast as described in Section 3.12.

(4) For purposes of Demand forecasting, ERCOT may choose to use the same forecast as that used for the Load forecast.

(5) ERCOT shall publish procedures describing the forecasting process on the ERCOT website.

3.10.2 Annual Planning Model

(1) For each of the next six years, ERCOT shall develop models for annual planning purposes that contain, as much as practicable, information consistent with the Network Operations Model. The "Annual Planning Model" for each of the next six years is a

model of the ERCOT power system (created, approved, posted, and updated regularly by ERCOT) as it is expected to operate during peak Load conditions for the corresponding future year.

(2) By October 15th of each year, ERCOT shall update, for each of the next six years, the ERCOT Planning Model and post it to the MIS Secure Area

(3) ERCOT shall make available to TSPs and/or Distribution Service Provider (DSPs) and all appropriate Market Participants, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, the transmission model used in transmission planning. ERCOT shall provide model information through the use of the Electric Power Research Institute (EPRI) and North American Electric Reliability Corporation (NERC) sponsored CIM and web-based Extensible Markup Language (XML) communications or Power System Simulator for Engineering (PSS/E) format.

(4) ERCOT shall make available to TSPs and/or Distribution Service Provider (DSPs) ~~post~~ the schedule for updating transmission information ~~on the MIS Secure Area~~.

(5) ERCOT shall coordinate updates to the Annual Planning Model with the Network Operations Model to ensure consistency of data within and between the Annual Planning Model and Network Operations Model to the extent practicable.

3.10.4 ERCOT Responsibilities

(1) ERCOT shall design, install, operate, and maintain its systems and establish applicable related processes to meet the State Estimator Standards for Transmission Elements that under typical system conditions potentially affect the calculation of Locational Marginal Prices (LMPs) as described in Section 3.10.7.5, Telemetry Standards, and Section 3.10.9, State Estimator Standards. ERCOT shall post all documents relating to the State Estimator Standards on the MIS Secure Area, except where otherwise stated in Section 3.10.9.6, Telemetry and State Estimator Performance Monitoring.

(2) During Real-Time, ERCOT shall calculate LMPs and take remedial actions to ensure that actual flow on a given Transmission Element is less than the Normal Rating and any calculated flow due to a contingency is less than the applicable Emergency Rating and 15-Minute Rating.

(3) ERCOT shall install Network Operations Model test facilities that will accommodate execution of a test Real-Time sequence and preliminary test LMP calculator to demonstrate the correct operation of new Network Operations Models prior to releasing the model to Market Participants for detail testing and verification. The Network Operations Model test facilities support power flow and contingency analyses to test the data set representation of a proposed transmission model update and simulate LMP calculations using typical test data.

(4) ERCOT shall install EMS test and simulation facilities that accommodate execution of the State Estimator and LMP calculator, respectively. These facilities will be used to conduct tests prior to placing a new model into ERCOT's production environment to

verify the new model's accuracy. The EMS test facilities allow a potential model to be tested before replacing the current production environment model. The EMS test and simulation facilities must perform Real-Time security analysis to test a proposed transmission model before replacing the current production environment model. The EMS State Estimator test facilities must have Real-Time ICCP links to test the state estimation function using actual Real-Time conditions. The EMS LMP test facilities must accept data uploads from the production environment providing Qualified Scheduling Entity (QSE) Resource offers, and telemetry via ICCP. If the production data are unavailable, ERCOT may employ a data simulation tool or process to develop test data sets for the LMP test facilities. For TSPs, ERCOT shall acquire model comparison software that will show all differences between subsequent versions of the Network Operations Model and shall make this information available to TSPs only within one week following test completion. For non-TSP Market Participants, ERCOT shall post the differences within one week following test completion between subsequent versions of the Redacted Network Operations Model on the MIS Secure Area. This comparison shall indicate differences in device parameters, missing or new devices, and status changes.

(5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP and Resource Entity shall provide reasonably accurate information at the time of the original submission.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP, DCTO, and Resource Entity shall provide reasonably accurate information at the time of the original submission.

(6) ERCOT may update the model on an interim basis, outside of the timeline described in Section 3.10.1, Time Line for Network Operations Model Changes, for the correction of temporary configuration changes in a system restoration situation, such as after a storm, or correction of impedances and ratings.

(7) Interim updates to the Network Operations Model caused by unintentional inconsistencies of the model with the physical transmission grid may be made. If an interim update is implemented, ERCOT shall report changes to the PUCT Staff and the IMM. ERCOT shall provide Notice via electronic means to all Market Participants and post the Notice on the MIS Secure Area detailing the changed model information and the

reason for the interim update within two Business Days following the report to PUCT Staff and the IMM.

(8) A TSP and Resource Entity, with ERCOT's assistance, shall validate its portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, to an environment of the ERCOT EMS where the Network Operations Model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results.

[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(8) TSPs, DCTOs, and Resource Entities, with ERCOT's assistance, shall validate their portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, to an environment of the ERCOT EMS where the Network Operations Model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results.

(9) ERCOT shall make available to TSPs, consistent with the requirements regarding ECEII, the Network Operations Model used to manage the reliability of the transmission system as well as proposed Network Operations Models to be implemented at a future date. ERCOT shall post on the MIS Secure Area the Redacted Network Operations Model, consistent with the requirements regarding release of ECEII, as well as proposed Redacted Network Operations Models to be implemented at a future date. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web-based XML communications.

3.10.9.6 Telemetry and State Estimator Performance Monitoring

(1) ERCOT shall monitor the performance of the State Estimator, Network Security Analysis, SCED, and LMP Calculator. ERCOT shall post a monthly report of these items on the MIS Secure Area, except for reports of State Estimator convergence rates that ERCOT shall post on the ERCOT website. ERCOT shall notify affected TSPs and QSEs of any lapses of observability of the transmission system.

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

(1) ERCOT shall monitor the performance of the State Estimator, Network Security Analysis, SCED, and LMP Calculator. ERCOT shall post a monthly report of these items on the MIS Secure Area, except for reports of State Estimator convergence rates that ERCOT shall post on the ERCOT website. ERCOT shall notify affected TSPs, QSEs, or DCTOs of any lapses of observability of the transmission system.

3.12 Load Forecasting

(1) ERCOT shall produce and use Load forecasts to serve operations and planning objectives.

(a) ERCOT shall update and post hourly on the ERCOT website, a "Seven-Day Load Forecast" as described in Section 3.12.1, Seven-Day Load Forecast, that provides forecasted hourly Load over the next 168 hours for each of the Weather Zones and for each of the Forecast Zones.

(b) ERCOT shall develop and post monthly on the ~~Market Information System (MIS) Secure Area~~ ERCOT website a "36-Month Load Forecast" that provides a daily minimum and maximum Load forecast for the next 36-months for the ERCOT Region, for each of the Weather Zones, and for each of the Forecast Zones. The 36-Month Load Forecast is used in the Outage coordination process and for Resource adequacy reporting.

[NPRR1004: Insert paragraph (c) below upon system implementation:]

(c) ERCOT shall generate and post daily on the ERCOT website Load distribution factors that provide hourly distribution for non-Private Use Network Loads by means of the Mid-Term Load Forecast (MTLF). Private Use Network Loads will be generated separately. If ERCOT decides, in its sole discretion, to change the Load distribution factors for reasons such as anticipated weather events or holidays, ERCOT shall select representative conditions as an input reasonably reflecting the anticipated Load in the Operating Day. ERCOT may also modify the Load distribution factors to account for predicted differences in network topology between the Load forecast and Operating Day. ERCOT may set auto error correction settings and apply Load forecast validation to better represent Load Profiles. Private Use Network Load distribution factor data is redacted from the ~~MIS~~ ERCOT website postings and all self-serve Load's distribution factors are set to zero when the data is used by the downstream applications.

(2) ERCOT shall produce and post to the ERCOT website an Intra-Hour Load Forecast (IHLF) that provides a rolling two hour five minute forecast of ERCOT-wide Load.

3.14.1 Reliability Must Run

Commented [EWG2]: Please note NPRR1246 also proposes changes to this section.

(1) RMR Service is the use by ERCOT, under contracts with Resource Entities, of capacity and energy from Generation Resources that otherwise would not operate and that are necessary to provide voltage support, stability or management of localized transmission constraints under applicable reliability criteria, where market solutions do not exist.

(a) Upon receiving a Notification of Suspension of Operations (NSO) from a Resource Entity as described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT may begin procurement of RMR Service under this Section.

(b) Before entering into an RMR Agreement, ERCOT shall assess alternatives to the proposed RMR Agreement. ERCOT shall evaluate and present in a written report posted on the Market Information System (MIS) Secure Area the information in items (i) through (iv) below. ERCOT is not limited in the number of additional scenarios it chooses to evaluate. The written report shall include an explanation as to why the items below are insufficient, either alone or in combination, to fill the requirement that will be met by the potential RMR Unit. The report shall be posted in the time frame required under paragraph (5) of Section 3.14.1.2, ERCOT Evaluation Process. The list of alternatives ERCOT must consider includes (as reasonable for each type of reliability concern identified):

(i) Re-dispatch/reconfiguration through operator instruction;

(ii) Automatic Mitigation Plans (AMPs) and Remedial Action Plans (RAPs);

(iii) Remedial Action Schemes (RASs) initiated on unit trips or Transmission Facilities' Outages; and

(iv) Any other operational alternatives deemed viable by ERCOT.

(c) ERCOT shall minimize the use of RMR Units as much as practicable subject to the other provisions of these Protocols. ERCOT may Dispatch an RMR Unit at any time for ERCOT System security.

(d) Each RMR Unit must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing.

(e) ERCOT may execute RMR Agreements for no less than one month and no more than one year, with one exception. ERCOT may execute an RMR Agreement for a term longer than 12 months if the Resource Entity must make a significant capital expenditure to meet environmental regulations or to ensure availability to continue operating the RMR Unit so as to make an RMR Agreement in excess of 12 months appropriate, in ERCOT's opinion. The term of a multi-year RMR Agreement must take into account the

appropriate RMR exit strategy discussed in Section 3.14.1.4, Exit Strategy from an RMR Agreement. In the event ERCOT chooses to contract for an RMR Unit for longer than one year, ERCOT shall annually re-evaluate the need for the RMR Unit under the criteria set forth in paragraph (b) above. If ERCOT determines the RMR Unit is no longer needed, ERCOT shall enter into exit negotiations with the contract signatories to attempt to exit the contract early. However, ERCOT shall not enter into such negotiations until a Market Notice is issued providing the anticipated RMR exit time frame. The RMR standard Agreement is included in Section 22, Attachment B, Standard Form Reliability Must-Run Agreement. ERCOT shall post each RMR Agreement in its entirety, including amendments or modifications thereto, within five Business Days of execution on the MIS Secure Area.

(f) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability according to the Operating Guides. A combined-cycle generation Facility must be treated as a single unit for RMR purposes unless the combustion turbine and the steam turbine can operate separately. If the steam turbine and combustion turbine can operate separately, and the steam turbine is powered by waste heat from more than one combustion turbine, the combustion turbine accepted for RMR Service and a proportionate part of the steam turbine must be treated as a single unit for RMR purposes. If the combustion turbine accepted for RMR Service can operate separately from the steam turbine, and only the combustion turbine is accepted as an RMR Unit, the RMR energy price will be reduced by the value of the combustion turbine's waste heat calculated at the Fuel Index Price (FIP), except when the steam turbine is Off-Line. ERCOT shall post to the MIS Secure Area the criteria upon which it evaluates whether an RMR Unit meets the test of operational necessity to support ERCOT System reliability within five Business Days of change and shall issue a Market Notice stating the determination is available. This includes the case where a unit previously identified by ERCOT as potentially needed for RMR Service is no longer needed regardless of whether an RMR Agreement was ever signed.

[NPRR1183: Replace paragraph (f) above with the following upon system implementation:]

(f) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability according to the Operating Guides. A combined-cycle generation Facility must be treated as a single unit for RMR purposes unless the combustion turbine and the steam turbine can operate separately. If the steam turbine and combustion turbine can operate separately, and the steam turbine is powered by waste heat from more than one combustion turbine, the combustion turbine accepted for RMR Service and a proportionate part of the steam turbine must be treated as a single unit for RMR purposes. If the combustion turbine accepted for RMR Service can operate separately from the steam turbine, and only the combustion turbine is accepted as an RMR Unit, the RMR energy price will be reduced by the value of the combustion turbine's waste heat calculated at the Fuel Index Price (FIP), except when the steam turbine is Off-Line.

(g) A Resource Entity cannot be compelled to enter into an RMR Agreement. A Resource Entity that owns or controls a Generation Resource that is uneconomic to remain in service can voluntarily petition ERCOT for contracted RMR status by following the process in this subsection. ERCOT shall determine whether the Generation Resource is necessary for system reliability based on the criteria set forth in this Section.

(h) ERCOT must contract for the entire capacity of each RMR Unit.

(i) ERCOT shall post on the ~~MIS Secure Area~~ERCOT website all information relative to the use of RMR Units including energy deployed monthly.

(j) The Resource Entity that owns or controls the RMR Unit may not use the RMR Unit for:

(i) Participating in the bilateral energy market;

(ii) Self-providing of energy except for plant auxiliary Load obligations under the RMR Agreement; and

(iii) Providing of Ancillary Service to any Entity.

(k) ERCOT shall issue a Market Notice on the need for an RMR Unit prior to entering negotiations for the RMR Unit. Such Market Notice shall include the link to the ERCOT final RMR evaluation, the Resource name and unit code, the name of the Resource Entity, the name of the Qualified Scheduling Entity (QSE) for the Resource, the Resource MW rating by Season, and potential duration of the RMR Agreement, including anticipated start and end dates.

(l) ERCOT shall, through the issuance of Market Notices, provide the same information, contemporaneously, about the need for, or elimination of an RMR Unit to all registered Market Participants, including QSEs and Resource Entities with RMR Units.

3.15 Voltage Support

(1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it on the ERCOT website~~Market Information System (MIS) Secure Area~~. ERCOT, the interconnecting TSP, or that TSP's agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions.

(2) All Generation Resources (including self-serve generating units) and Energy Storage Resources (ESRs) that are connected to Transmission Facilities and that have a gross unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

(3) Except as reasonably necessary to ensure reliability or operational efficiency, TSPs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource or ESR.

(4) Each Generation Resource and ESR required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource or ESR shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource or an ESR required to provide VSS is issued a new Voltage Set Point, that Generation Resource or ESR shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements;

(e) For Generation Resources, the Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource's Corrected Unit Reactive Limit (CURL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR's nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP's agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability. For ESRs, the Reactive Power capability shall be available at all MW levels, when charging or discharging, and may be met through a combination of the ESR's CURL, and/or dynamic VAr-capable devices. For any ESR that achieved Initial Synchronization before December 16, 2019, the requirement to have Reactive Power capability when charging does not apply if the Resource Entity for the ESR has submitted a notarized attestation to

ERCOT stating that, since the date of Initial Synchronization, the ESR has been unable to comply with this requirement without physical or software changes/modifications, and ERCOT has provided written confirmation of the exemption to the Resource Entity. The exemption shall apply only to the extent of the ESR's inability to comply with the requirement when the ESR is charging.

(f) For any Generation Resource or Energy Storage Resource (ESR) that is part of a Self-Limiting Facility, the capabilities described in paragraphs (a) and (b) above shall be determined based on the Self-Limiting Facility's established MW Injection limit and, if applicable, established MW Withdrawal limit.

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources and ESRs must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

(6) Except for a Generation Resource or an ESR subject to Planning Guide Section 5.2.1, Applicability, a Generation Resource or an ESR that has already been commissioned is not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

(7) Wind-powered Generation Resources (WGRs) that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 ("Existing Non-Exempt WGRs"), must be capable of producing a defined quantity of Reactive Power to maintain a set point in the Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (4) above, except in the circumstances described in paragraph (a) below.

(a) Existing Non-Exempt WGRs whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above must conduct an engineering study using the Summer/Fall 2010 on-peak/off-peak Voltage Profiles, or conduct performance testing to determine their actual Reactive Power capability. Any study or testing results must be accepted by ERCOT. The Reactive Power requirements applicable to these Existing Non-Exempt WGRs will be the greater of: the leading and lagging Reactive Power capabilities established by the Existing Non-Exempt WGR's engineering study or testing results; or Reactive Power proportional to the real power output of the Existing Non-Exempt WGR (this Reactive Power profile is depicted graphically as a triangle) sufficient to provide an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the WGR's set point in the Voltage Profile established by ERCOT, and both measured at the POIB.

(i) Existing Non-Exempt WGRs shall submit the engineering study results or testing results to ERCOT no later than five Business Days after its completion.

(ii) Existing Non-Exempt WGRs shall update any and all Resource Registration data regarding their Reactive Power capability documented by the engineering study results or testing results.

(iii) If the Existing Non-Exempt WGR's engineering study results or testing results indicate that the WGR is not able to provide Reactive Power capability that meets the triangle profile described in paragraph (a) above, then the Existing Non-Exempt WGR will take steps necessary to meet that Reactive Power requirement depicted graphically as a triangle by a date mutually agreed upon by the Existing Non-Exempt WGR and ERCOT. The Existing Non-Exempt WGR may meet the Reactive Power requirement through a combination of the WGR's Unit Reactive Limit (URL) and/or automatically switchable static VAr-capable devices and/or dynamic VAr-capable devices. No later than five Business Days after completion of the steps to meet that Reactive Power requirement, the Existing Non-Exempt WGR will update any and all Resource Registration data regarding its Reactive Power and provide written notice to ERCOT that it has completed the steps necessary to meet its Reactive Power requirement.

(iv) For purposes of measuring future compliance with Reactive Power requirements for Existing Non-Exempt WGRs, results from performance testing or the Summer/Fall 2010 on-peak/off-peak Voltage Profiles utilized in the Existing Non-Exempt WGR's engineering study shall be the basis for measuring compliance, even if the Voltage Profiles provided to the Existing Non-Exempt WGR are revised for other purposes.

(b) Existing Non-Exempt WGRs whose current design allows them to meet the Reactive Power requirements established in paragraph (4) above (depicted graphically as a rectangle) shall continue to comply with that requirement. ERCOT, with cause, may request that these Existing Non-Exempt WGRs provide further evidence, including an engineering study, or performance testing, to confirm accuracy of Resource Registration data supporting their Reactive Power capability.

(8) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the criteria in the ERCOT Operating Guides.

(9) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation

Resource's URL that was submitted to ERCOT and established per the criteria in the Operating Guides.

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple units including IRRs shall, at a Resource Entity's option, be treated as a single Resource if the units are connected to the same transmission bus.

(11) Resource Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the CURL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Resource Entity and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

(12) A Resource Entity and TSP may enter into an agreement in which the Generation Resource or ESR compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource or ESR shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification.

(14) Generation Resources or ESRs shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

(b) The number of wind turbines out of service and not available for operation.

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of PV equipment that is not able to communicate and whose status is unknown; and

(b) The capacity of PV equipment that is out of service and not available for operation.

[NPRR1029: Insert paragraph (17) below upon system implementation and renumber accordingly:]

(17) Each DC-Coupled Resource must provide a Real-Time SCADA point that communicates to ERCOT the capacity of the intermittent renewable generation component of the Resource that is available for real power and/or Reactive Power injection into the ERCOT System. Each DC-Coupled Resource must also provide Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of any PV generation equipment that is not able to communicate and whose status is unknown;

(b) The capacity of any PV generation equipment that is out of service and not available for operation;

(c) The number of any wind turbines that are not able to communicate and whose status is unknown; and

(d) The number of any wind turbines out of service and not available for operation.

(17) For the purpose of complying with the Reactive Power requirements under this Section 3.15, Reactive Power losses that occur on privately-owned transmission lines behind the POIB may be compensated by automatically switchable static VAr-capable devices.

3.20.1 Evaluation of Chronic Congestion

(1) ERCOT shall evaluate chronic congestion monthly and shall report on the ERCOT website the results of its evaluation to the appropriate Technical Advisory Committee (TAC) subcommittee(s). The report must identify the constraint(s) causing the chronic congestion.

6.3.1 Activities for the Adjustment Period

(1) The following table summarizes the timeline for the Adjustment Period and the activities of QSEs and ERCOT. 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:

Adjustment Period	QSE Activities	ERCOT Activities
Time – From 1800 in the Day-Ahead up to one hour	Submit and update Energy Trades, Capacity Trades, Self-Schedules, and Ancillary Service Trades	~~Post shift schedules on the Market Information System (MIS) Secure Area~~

Adjustment Period	QSE Activities	ERCOT Activities
before the start of the Operating Hour	Submit and update Output Schedules Submit and update Incremental and Decremental Energy Offer Curves for Dynamically Scheduled Resources (DSRs) ***[NPRR1000: Delete the item above upon system implementation.]*** Submit and update Energy Offer Curves and/or RTM Energy Bids ***[NPRR1188: Replace the item above with the following upon system implementation:]*** Submit and update Energy Offer Curves and/or Energy Bid Curves ***[NPRR1014: Insert the item below upon system implementation:]*** Submit Energy Bid/Offer Curves for Energy Storage Resources (ESRs) Update Current Operating Plan (COP) Request Resource decommitments Submit Three-Part Supply Offers for Off-Line Generation Resources Submit offers for any Supplemental Ancillary Service Markets ***[NPRR1010 and NPRR1014: Replace applicable portions of the item above with the following upon system implementation of the Real-***	Validate Energy Trades, Capacity Trades, Self-Schedules, and Ancillary Service Trades and identify invalid or mismatched trades Validate Output Schedules Validate Incremental and Decremental Energy Offer Curves Validate Energy Offer Curves and/or RTM Energy Bids ***[NPRR1188: Replace the item above with the following upon system implementation:]*** Validate Energy Offer Curves and/or Energy Bid Curves ***[NPRR1014: Insert the item below upon system implementation:]*** Validate Energy Bid/Offer Curves Validate COP including validation of the deliverability of Ancillary Services from Resources for the next Operating Period Review and approve or reject Resource decommitments Validate Three-Part Supply Offers Publish Notice of Need to Procure Additional Ancillary Service capacity if required ***[NPRR1010 and NPRR1014: Replace applicable portions of the item above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or***

Adjustment Period	QSE Activities	ERCOT Activities
	Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:] Submit and update Ancillary Service Offers Communicate Resource Forced Outages	***upon system implementation for NPRR1014:]*** Publish Notice of need to update the Ancillary Service Plan if required and update the Ancillary Service Demand Curves (ASDCs) for the affected hours and Ancillary Services Validate Ancillary Service Offers At the end of the Adjustment Period snap-shot the net capacity credits for Hourly Reliability Unit Commitment (HRUC) Settlement Update Short-Term Wind Power Forecast (STWPF) Update Short-Term PhotoVoltaic Power Forecast (STPPF) Execute the Hour-Ahead Sequence Notify the QSE via the MIS Certified Area that an Energy Offer Curve, RTM Energy Bid or Output Schedule has not yet been submitted for a Resource as a reminder that one of the three must be submitted by the end of the Adjustment Period ***[NPRR1188: Replace the item above with the following upon system implementation:]*** Notify the QSE via the MIS Certified Area that an Energy Offer Curve, Energy Bid Curve or Output Schedule has not yet been submitted for a Resource as a reminder that one of the three must be submitted by the end of the Adjustment Period ***[NPRR1010 and NPRR1014: Insert applicable portions of the items below upon system***

Adjustment Period	QSE Activities	ERCOT Activities
		implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:] Notify the QSE via the MIS Certified Area that an Ancillary Service Offer has not yet been submitted for a Resource by the end of the Adjustment Period Notify the QSE via the MIS Certified Area that an Energy Bid/Offer Curve has not yet been submitted for an ESR by the end of the Adjustment Period

6.5.1.2 Centralized Dispatch

(1) ERCOT shall centrally Dispatch Resources and Transmission Facilities under these Protocols, including deploying energy by establishing Base Points, and Emergency Base Points, and by deploying Regulation Service, ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) to ensure operational security. Responsive Reserve (RRS) shall be self-deployed in response to frequency deviations or as specified in Nodal Operating Guide Section 4.8, Responsive Reserve Service During Scarcity Conditions.

(2) ERCOT shall verify that either an Energy Offer Curve providing prices for the Resource between its High Sustained Limit (HSL) and Low Sustained Limit (LSL) or an Output Schedule has been submitted for each On-Line Resource an hour before the end of the Adjustment Period for the upcoming Operating Hour. ERCOT shall notify QSEs that have not submitted an Output Schedule or Energy Offer Curve through the Market Information System (MIS) Certified Area.

[NPRR1014: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall verify that either an Energy Offer Curve or Energy Bid/Offer Curve providing prices for the Resource between its High Sustained Limit (HSL) and Low Sustained Limit (LSL) or an Output Schedule has been submitted for each On-Line Resource an hour before the end of the Adjustment Period for the upcoming Operating Hour. ERCOT shall notify QSEs that have not submitted an Output Schedule or Energy Offer Curve or Energy Bid/Offer Curve through the Market Information System (MIS) Certified Area.

[NPRR1010 and NPRR1014: Insert applicable portions of paragraph (3) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014; and renumber accordingly:]

(3) If a Resource is scheduled to be On-Line and available to provide an Ancillary Service, but does not have any Ancillary Service Offers for which the Resource is qualified to provide, then at the end of the Adjustment Period, ERCOT shall notify the Resource's QSE through the MIS Certified Area.

(3) ERCOT may only issue Dispatch Instructions for the Real-Time operation of Transmission Facilities to a TSP, for the Real-Time operation of distribution facilities to a Distribution Service Provider (DSP), or for a Resource to the QSE that represents it.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) In Real-Time operations, ERCOT may only issue Dispatch Instructions for Direct Current Ties (DC Ties) to the appropriate Direct Current Tie Operator (DCTO), for Transmission Facilities to a Transmission Service Provider (TSP), for distribution facilities to a Distribution Service Provider (DSP), or for a Resource to the QSE that represents it.

~~(4) ERCOT shall post shift schedules on the MIS Secure Area.~~

Revised ERCOT Impact Analysis Report

NPRR Number	1240	NPRR Title	Access to Transmission Planning Information
Impact Analysis Date		October 29, 2024	
Estimated Cost/Budgetary Impact		Between $40k and $60k	
Estimated Time Requirements		The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 3 to 6 months	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • ERCOT Website and MIS Systems 44% • Data Management & Analytic Systems 44% • Channel Management Systems 11%	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this NPRR.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

NPRR Number	1245	NPRR Title	Additional Clarifying Revisions to Real-Time Co-Optimization
Date of Decision		December 3, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: Not applicable	
Proposed Effective Date		Upon system implementation of PR447, Real-Time Co-Optimization (RTC)	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		3.2.5, Publication of Resource and Load Information 4.2.1.2, Ancillary Service Obligation Assignment and Notice 4.4.7.2, Ancillary Service Offers 4.7.2.1, Resource-Specific Ancillary Service Offer Criteria 4.4.9.3.1, Energy Offer Curve Criteria 4.4.9.4.1, Mitigated Offer Cap 4.4.12, Determination of Ancillary Service Demand Curves for the Day-Ahead Market and Real-Time Market 4.6.4.1.3, Responsive Reserve Payment 5.5.2, Reliability Unit Commitment (RUC) Process 6.3, Adjustment Period and Real-Time Operations Timeline 6.4.1, Capacity Trade, Energy Trade, Self-Schedule, and Ancillary Service Trades 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adder 6.6.5.6, Resources Exempt from Deviation Charges 6.6.9.1, Payment for Emergency Operations Settlement 6.7.4, Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations 6.7.5.2, Regulation Up Service Payments and Charges 6.7.5.3, Regulation Down Service Payments and Charges 6.7.5.4, Responsive Reserve Payments and Charges 6.7.5.5, Non-Spinning Reserve Service Payments and Charges 6.7.5.6, ERCOT Contingency Reserve Service Payments and Charges 6.7.5.7, Real-Time Derated Ancillary Service Capability Payment 6.7.5.8, Real-Time Derated Ancillary Service Capability Charge 7.9.3.1, DAM Congestion Rent	

Board Report

	9.14.10, Settlement for Market Participants Impacted by Omitted Procedures or Manual Actions to Resolve the DAM 25.5.1, Settlement Activity for a Market Suspension 25.5.2, Market Suspension Make-Whole Payment
Related Documents Requiring Revision/Related Revision Requests	None
Revision Description	This Nodal Protocol Revision Request (NPRR) was authored by ERCOT during the development of business requirements and adds certain clarifying revisions to the Protocols to address several gaps and errors in the existing approved Protocols for the RTC+B project. The explanations for each of the various revisions were posted in a summary spreadsheet on the July 17, 2024 RTCBTF meeting page. These revisions broadly fall into three categories: 1. Catching up the Protocol language with other NPRRs that have been passed since the approval of the relevant RTC+B NPRRs, such as NPRR1093, Load Resource Participation in Non-Spinning Reserve; 2. Addressing errors in the language such as Settlement equation subscripts and references to the Supplemental Ancillary Service Market (SASM); and 3. Adding Protocol language to provide additional clarification based on the software requirements that have been developed for the RTC+B project. ERCOT invites review of this NPRR from the RTC+B Task Force. It is also worth noting these changes have no system impacts as they reflect the current RTC+B business requirements and interface requirements for Market Participants.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s)

Board Report

	☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR adds certain clarifying revisions to the Protocols to reflect updates from RTC+B. These edits address gaps and errors in the language and align the Protocols with the systems being developed for the RTC+B project. These edits were discussed with Real-Time Co-optimization plus Batteries Task Force (RTCBTF) at their meeting on July 17, 2024.
PRS Decision	On 9/12/24, PRS voted unanimously to recommend approval of NPRR1245 as amended by the 9/5/24 ERCOT comments as revised by PRS. All Market Segments participated in the vote. On 10/17/24, PRS voted unanimously to endorse and forward to TAC the 9/12/24 PRS Report and 7/30/24 Impact Analysis for NPRR1245. All Market Segments participated in the vote.
Summary of PRS Discussion	On 9/12/24, ERCOT Staff provided an overview of NPRR1245, the 9/5/24 ERCOT comments, and desktop edits to align formula revisions within Section 4.4.12. On 10/17/24, there was no discussion.
TAC Decision	On 10/30/24, TAC voted unanimously to recommend approval of NPRR1245 as recommended by PRS in the 10/17/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/30/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed – with the exception of the IMM Opinion which was not available for TAC review. ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)

Board Report

ERCOT Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1245 as recommended by TAC in the 10/30/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1245 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1245.
ERCOT Opinion	ERCOT supports approval of NPRR1245.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1245 and believes the market impact for NPRR1245 implements several corrections and clarifications to Protocols and RTC grey-boxes, along with relevant updates to RTC grey-boxes necessitated by subsequent NPRR approvals.

Sponsor	
Name	Dave Maggio / Magie Shanks
E-mail Address	david.maggio@ercot.com / magie.shanks@ercot.com
Company	ERCOT
Phone Number	512-248-6998 / 512-248-6472
Cell Number	
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**

Board Report

ERCOT 090524	Proposed additional revisions to address two gaps identified during the development of business requirements for RTC

Market Rules Notes

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

- NPRR1058, Resource Offer Modernization (unboxed 8/23/24)
  - Section 3.2.5
  - Section 4.4.9.3.1
  - Section 4.4.9.4.1
  - Section 6.6.5.6
- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources (incorporated 12/1/24)
  - Section 3.2.5
  - Section 4.4.7.2
  - Section 6.5.7.3.1
  - Section 6.6.5.6
  - Section 7.9.3.1
  - Section 9.14.10
- NPRR1216, Implementation of Emergency Pricing Program (incorporated 10/1/24)
  - Section 4.4.12

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

- NPRR1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
  - Section 6.5.7.3.1
- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  - Section 4.4.7.2
  - Section 4.4.12
  - Section 5.5.2
  - Section 6.5.7.3.1
  - Section 9.14.10
- NPRR1238, Voluntary Registration of Loads with Curtailable Load Capabilities
  - Section 6.5.7.3.1
- NPRR1239, Access to Market Information
  - Section 4.4.9.4.1
  - Section 5.5.2
- NPRR1255, Introduction of Mitigation of ESRs

- Section 4.4.9.4.1

Proposed Protocol Language Revision

3.2.5 Publication of Resource and Load Information

(1) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System and, if applicable, for each Disclosure Area, the information derived from the first complete execution of Security-Constrained Economic Dispatch (SCED) in each 15-minute Settlement Interval. The Disclosure Area is the 2003 ERCOT CMZs. Posting requirements will be applicable to Generation Resources and Controllable Load Resources physically located in the defined Disclosure Area. This information shall not be posted if the posting of the information would reveal any individual Market Participant's Protected Information. The information posted by ERCOT shall include:

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(1) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System and, if applicable, for each Disclosure Area, the information derived from each execution of SCED. The Disclosure Area is the 2003 ERCOT CMZs. Posting requirements will be applicable to Generation Resources, ESRs, and Controllable Load Resources physically located in the defined Disclosure Area. This information shall not be posted if the posting of the information would reveal any individual Market Participant's Protected Information. The information posted by ERCOT shall include:

(a) An aggregate energy supply curve based on non-IRR Generation Resources with Energy Offer Curves that are available to SCED. The energy supply curves will be calculated beginning at the sum of the Low Sustained Limits (LSLs) and ending at the sum of the HSLs for non-IRR Generation Resources with Energy Offer Curves, with the dispatch for each Generation Resource constrained between the Generation Resource's LSL and HSL. The result will represent the ERCOT System energy supply curve economic dispatch of the non-IRR Generation Resources with Energy Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

(b) An aggregate energy supply curve based on Wind-powered Generation Resources (WGRs) with Energy Offer Curves that are available to SCED. The energy supply curves will be calculated beginning at the sum of the LSLs and ending at the sum of the HSLs for WGRs with Energy Offer Curves, with the dispatch for each WGR constrained between the WGR's LSL and HSL. The result will represent the ERCOT System energy supply curve economic dispatch of the

WGRs with Energy Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

(c) An aggregate energy supply curve based on PhotoVoltaic Generation Resources (PVGRs) with Energy Offer Curves that are available to SCED. The energy supply curves will be calculated beginning at the sum of the LSLs and ending at the sum of the HSLs for PVGRs with Energy Offer Curves, with the dispatch for each PVGR constrained between the PVGR's LSL and HSL. The result will represent the ERCOT System energy supply curve economic dispatch of the PVGRs with Energy Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

[NPRR1014: Insert paragraph (d) below upon system implementation and renumber accordingly:]

(d) An aggregated energy supply and demand curve based on Energy Bid/Offer Curves that are available to SCED. The curves will be calculated beginning at the sum of the LSLs and ending at the sum of the HSLs for the Energy Bid/Offer Curves, with the dispatch for each Resource constrained between the Resource's LSL and HSL. The result will represent the ERCOT System energy supply and demand curve economic dispatch of the ESRs with Energy Bid/Offer Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

(d) The sum of LSLs, sum of Output Schedules, and sum of HSLs for Generation Resources without Energy Offer Curves;

[NPRR1014: Replace paragraph (d) above with the following upon system implementation:]

(e) The sum of LSLs, sum of Output Schedules, and sum of HSLs for Generation Resources without Energy Offer Curves and ESRs without Energy Bid/Offer Curves;

(e) The sum of the Base Points, High Ancillary Service Limit (HASL) and Low Ancillary Service Limit (LASL) of non-IRR Generation Resources with Energy Offer Curves, sum of the Base Points, HASL and LASL of WGRs with Energy Offer Curves, sum of the Base Points, HASL and LASL of PVGRs with Energy Offer Curves, and the sum of the Base Points, HASL and LASL of all remaining Generation Resources dispatched in SCED;

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(f) The sum of the Base Points of non-IRR Generation Resources with Energy Offer Curves, sum of the Base Points of WGRs with Energy Offer Curves, sum of the Base Points of PVGRs with Energy Offer Curves, sum of the Base Points of ESRs with Energy Bid/Offer Curves, and the sum of the Base Points of all remaining Resources dispatched in SCED;

(f) The sum of the telemetered Generation Resource net output used in SCED; and

(g) An aggregate energy Demand curve based on the Real-Time Market (RTM) Energy Bid curves available to SCED. The energy Demand curve will be calculated beginning at the sum of the Low Power Consumptions (LPCs) and ending at the sum of the Maximum Power Consumptions (MPCs) for Controllable Load Resources with RTM Energy Bids, with the dispatch for each Controllable Load Resource constrained between the Controllable Load Resource's LPC and MPC. The result will represent the ERCOT System Demand response capability available to SCED of the Controllable Load Resources with RTM Energy Bids at various pricing points, not taking into consideration any physical limitations of the ERCOT System.

[NPRR1014 and NPRR1188: Replace applicable portions of paragraph (g) above with the following upon system implementation:]

(h) An aggregate energy Demand curve based on the Energy Bid Curves available to SCED. The energy Demand curve will be calculated beginning at the sum of the Low Power Consumptions (LPCs) and ending at the sum of the Maximum Power Consumptions (MPCs), with the dispatch for each CLR constrained between the CLR's LPC and MPC. The result will represent the ERCOT System Demand response capability available to SCED of the CLRs with Energy Bid Curves at various pricing points, not taking into consideration any physical limitations of the ERCOT System;

[NPRR1007 and NPRR1014: Insert applicable portions of paragraphs (i)-(k) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(i) The aggregate Ancillary Service Offers (prices and quantities) in the RTM for each type of Ancillary Service regardless of a Resource's On-Line or Off-Line status. For RRS, ERCOT shall separately post aggregated offers from Resources providing Primary Frequency Response, Fast Frequency Response (FFR), and Load Resources controlled by high-set under-frequency relays. For

ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin), ERCOT shall separately post aggregated offers from Resources that are SCED-dispatchable and those that are manually dispatched. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers~~The aggregate Ancillary Service Offers (prices and quantities) in the RTM, for each type of Ancillary Service. For Responsive Reserve (RRS) and ERCOT Contingency Reserve Service (ECRS), ERCOT shall separately post aggregated offers from Generation Resources, Energy Storage Resources (ESRs), Controllable Load Resources, and Load Resources other than Controllable Load Resources. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers~~;

(j) The sum of the Base Points of ESRs in discharge mode; and

(k) The sum of the Base Points of ESRs in charge mode.

(2) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System the following information derived from the first complete execution of SCED in each 15-minute Settlement Interval:

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(2) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website for the ERCOT System the following information derived from each execution of SCED:

(a) Each telemetered Dynamically Scheduled Resource (DSR) Load, and the telemetered DSR net output(s) associated with each DSR Load; and

[NPRR1000: Delete paragraph (a) above upon system implementation and renumber accordingly.]

(b) The actual ERCOT Load as determined by subtracting the DC Tie Resource actual telemetry from the sum of the telemetered Generation Resource net output as used in SCED.

(3) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website the following information for the ERCOT System and, if applicable, for each Disclosure Area from the Day-Ahead Market (DAM) for each hourly Settlement Interval:

(a) An aggregate energy supply curve based on all energy offers that are available to the DAM, not taking into consideration Resource Startup Offer or Minimum-

Energy Offer or any physical limitations of the ERCOT System. The result will represent the energy supply curve at various pricing points for energy offers available in the DAM;

(b) Aggregate minimum energy supply curves based on all Minimum-Energy Offers that are available to the DAM;

(c) An aggregate energy Demand curve based on the DAM Energy Bid curves available to the DAM, not taking into consideration any physical limitations of the ERCOT System;

(d) The aggregate amount of cleared energy bids and offers including cleared Minimum-Energy Offer quantities;

(e) The aggregate Ancillary Service Offers (prices and quantities) in the DAM, for each type of Ancillary Service regardless of a Resource's On-Line or Off-Line status. For Responsive Reserve (RRS), ERCOT shall separately post aggregated offers from Resources providing Primary Frequency Response, Fast Frequency Response (FFR), and Load Resources controlled by high-set under-frequency relays. For ERCOT Contingency Reserve Service (ECRS), ERCOT shall separately post aggregated offers from Resources that are SCED-dispatchable and those that are manually dispatched. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers;

(f) The aggregate Self-Arranged Ancillary Service Quantity, for each type of service, by hour. For RRS, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources providing Primary Frequency Response, FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources that are SCED-dispatchable and those that are manually dispatched;

(g) The aggregate amount of cleared Ancillary Service Offers. For RRS, ERCOT shall separately post aggregated Ancillary Service Offers from Resources providing Primary Frequency Response, FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS, ERCOT shall separately post aggregated Ancillary Service Offers from Resources that are SCED-dispatchable and those that are manually dispatched; and

(h) The aggregate Point-to-Point (PTP) Obligation bids (not-to-exceed price and quantities) for the ERCOT System and the aggregate PTP Obligation bids that sink in the Disclosure Area for each Disclosure Area.

[NPRR1007, NPRR1014, and NPRR1188: Replace applicable portions of paragraph (3) above with the following upon system implementation for NPRR1014 or NPRR1188; or

upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

(3) Two days after the applicable Operating Day, ERCOT shall post on the ERCOT website the following information for the ERCOT System and, if applicable, for each Disclosure Area from the DAM for each hourly Settlement Interval:

(a) An aggregate energy supply curve based on all energy offers that are available to the DAM, including the offer portion of Energy Bid/Offer Curves submitted for ESRs, not taking into consideration Resource Startup Offer or Minimum-Energy Offer or any physical limitations of the ERCOT System. The result will represent the energy supply curve at various pricing points for energy offers available in the DAM;

(b) Aggregate minimum energy supply curves based on all Minimum-Energy Offers that are available to the DAM;

(c) An aggregate energy Demand curve based on the DAM Energy Bids and Energy Bid Curves from CLRs and including the bid portion of Energy Bid/Offer Curves available to the DAM, not taking into consideration any physical limitations of the ERCOT System;

(d) The aggregate amount of cleared energy bids and offers including cleared Minimum-Energy Offer quantities;

(e) The aggregate Ancillary Service Offers (prices and quantities) in the DAM, for each type of Ancillary Service regardless of a Resource's On-Line or Off-Line status and including Ancillary Service Only Offers. For RRS, ERCOT shall separately post aggregated offers from Resources providing Primary Frequency Response (including Ancillary Service Only Offers), ~~Fast Frequency Response (~~FFR~~)~~, and Load Resources controlled by high-set under-frequency relays. For ~~ERCOT Contingency Reserve Service (~~ECRS~~)~~ and Non-Spin, ERCOT shall separately post aggregated offers from Resources that are SCED-dispatchable (including Ancillary Service Only Offers) and those that are manually dispatched. Linked Ancillary Service Offers will be included as non-linked Ancillary Service Offers;

(f) The aggregate Self-Arranged Ancillary Service Quantity, for each type of service, by hour. For RRS, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources providing Primary Frequency Response, FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS and Non-Spin, ERCOT shall separately post aggregated Self-Arranged Ancillary Service Quantities from Resources that are SCED-dispatchable and those that are manually dispatched;

(g) The aggregate amount of cleared Resource-specific Ancillary Service Offers and Ancillary Service Only Offers. For RRS, ERCOT shall separately post

aggregated Ancillary Service Offers from Resources providing Primary Frequency Response (including Ancillary Service Only Offers), FFR, and Load Resources controlled by high-set under-frequency relays. For ECRS and Non-Spin, ERCOT shall separately post aggregated Ancillary Service Offers from Resources that are SCED-dispatchable (including Ancillary Service Only Offers) and those that are manually dispatched; and

(h) The aggregate Point-to-Point (PTP) Obligation bids (not-to-exceed price and quantities) for the ERCOT System and the aggregate PTP Obligation bids that sink in the Disclosure Area for each Disclosure Area.

(4) ERCOT shall post on the ERCOT website the following information for each Resource for each 15-minute Settlement Interval 60 days prior to the current Operating Day:

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(4) ERCOT shall post on the ERCOT website the following information for each Resource for each execution of SCED 60 days prior to the current Operating Day:

(a) The Generation Resource name and the Generation Resource's Energy Offer Curve (prices and quantities):

(i) As submitted;

(ii) As submitted and extended (or truncated) with proxy Energy Offer Curve logic by ERCOT to fit to the operational HSL and LSL values that are available for dispatch by SCED; and

(iii) As mitigated and extended for use in SCED, including the Incremental and Decremental Energy Offer Curves for DSRs;

[NPRR1000: Replace paragraph (iii) above with the following upon system implementation:]

(iii) As mitigated and extended for use in SCED;

[NPRR1007 and NPRR1014: Insert applicable portions of paragraph (b) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014; and renumber accordingly:]

(b) The Resource name and the Resource's Ancillary Service Offer Curve (prices and quantities) for each type of Ancillary Service:

(i) As submitted; and

(ii) As submitted and extended with proxy Ancillary Service Offer Curve logic by ERCOT.

(b) The Load Resource name and the Load Resource's bid to buy (prices and quantities);

[NPRR1188: Replace paragraph (b) above with the following upon system implementation:]

(b) The Load Resource name and the Load Resource's Energy Bid Curve (prices and quantities);

(c) The Generation Resource name and the Generation Resource's Output Schedule;

(d) For a DSR, the DSR Load and associated DSR name and DSR net output;

[NPRR1000: Delete paragraph (d) above upon system implementation and renumber accordingly.]

(e) The Generation Resource name and actual metered Generation Resource net output;

(f) The self-arranged Ancillary Service by service for each QSE;

(g) The following Generation Resource data using a single snapshot during the first SCED execution in each Settlement Interval:

(i) The Generation Resource name;

(ii) The Generation Resource status;

(iii) The Generation Resource HSL, LSL, HASL, LASL, High Dispatch Limit (HDL), and Low Dispatch Limit (LDL);

(iv) The Generation Resource Base Point from SCED;

(v) The telemetered Generation Resource net output used in SCED;

(vi) The Ancillary Service Resource Responsibility for each Ancillary Service;

(vii) The Generation Resource Startup Cost and minimum energy cost used in the Reliability Unit Commitment (RUC); and

[NPRR1007 and NPRR1014: Replace applicable portions of paragraph (g) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014:]

(h) The following Generation Resource data using a snapshot from each execution of SCED:

(i) The Generation Resource name;

(ii) The Generation Resource status;

(iii) The Generation Resource HSL, LSL, High Dispatch Limit (HDL), and Low Dispatch Limit (LDL);

(iv) The Generation Resource Base Point from SCED;

(v) The telemetered Generation Resource net output used in SCED;

(vi) The Ancillary Service Resource awards for each Ancillary Service;

(vii) The Generation Resource Startup Cost and minimum energy cost used in the Reliability Unit Commitment (RUC);

(viii) The telemetered Normal Ramp Rates;

(ix) The telemetered Ancillary Service capabilities; and

(h) The following Load Resource data using a single snapshot during the first SCED execution in each Settlement Interval:

(i) The Load Resource name;

(ii) The Load Resource status;

(iii) The MPC for a Load Resource;

(iv) The LPC for a Load Resource;

(v) The Load Resource HASL, LASL, HDL, and LDL, for a Controllable Load Resource that has a Resource Status of ONRGL or ONCLR for the interval snapshot;

(vi) The Load Resource Base Point from SCED, for a Controllable Load Resource that has a Resource Status of ONRGL or ONCLR for the interval snapshot;

(vii) The telemetered real power consumption; and

(viii) The Ancillary Service Resource Responsibility for each Ancillary Service.

[NPRR1007, NPRR1014, and NPRR1204: Replace applicable portions of paragraph (h) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007 and NPRR1204; or upon system implementation for NPRR1014:]

(i) The following Load Resource data using a snapshot from each execution of SCED:

(i) The Load Resource name;

(ii) The Load Resource status;

(iii) The MPC for a Load Resource;

(iv) The LPC for a Load Resource;

(v) The Load Resource HDL and LDL, for a Controllable Load Resource that has a Resource Status of ONL;

(vi) The Load Resource Base Point from SCED, for a Controllable Load Resource that has a Resource Status of ONL;

(vii) The telemetered real power consumption;

(viii) The Ancillary Service Resource awards for each Ancillary Service;

(ix) The telemetered self-provided Ancillary Service amount for each Ancillary Service;

(x) The telemetered Normal Ramp Rates;

(xi) The telemetered Ancillary Service capabilities; and

(j) The ESR name and the ESR's Energy Bid/Offer Curve (prices and quantities):

(i) As submitted; and